

results of a required sample of sulfur content, GCV or density is missing or invalid in the current calendar year. The substitute data value(s) shall be used until the next valid

sample for the missing parameter(s) is obtained. Note that only actual sample results shall be used to determine the "highest value from the previous year" when

that reporting option is used; missing data values shall not be used in the determination.

TABLE D-6.—MISSING DATA SUBSTITUTION PROCEDURES FOR SULFUR, DENSITY, AND GROSS CALORIFIC VALUE DATA

Parameter	Missing data substitution maximum potential value
Oil Sulfur Content	3.5 percent for residual oil, or 1.0 percent for diesel fuel.
Oil Density	8.5 lb/gal for residual oil, or 7.4 lb/gal for diesel fuel.
Oil GCV	19,500 Btu/lb for residual oil, or 20,000 Btu/lb for diesel fuel.
Gas Sulfur Content	0.3 gr/100 scf for pipeline natural gas, or 1.0 gr/100 scf for natural gas, or Twice the highest total sulfur content value recorded in the previous 30 days when sampling gaseous fuel daily or hourly.
Gas GCV/Heat Content	1100 Btu/scf for pipeline natural gas, natural gas or landfill gas, or 1500 for butane or refinery gas. 2100 Btu/scf for propane or any other gaseous fuel.

2.4.2 Whenever data are missing from any fuel flowmeter that is part of an excepted monitoring system under appendix D or E to this part, where the fuel flowmeter data are required to determine the amount of fuel combusted by the unit, use the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix to account for the flow rate of fuel combusted at the unit for each hour during the missing data period. In addition, a fuel flowmeter used for measuring fuel combusted by a peaking unit may use the simplified fuel flow missing data procedure in section 2.4.2.1 of this appendix.

2.4.2.1 Simplified Fuel Flow Missing Data for Peaking Units

If no fuel flow rate data are available for a fuel flowmeter system installed on a peaking unit (as defined in § 72.2 of this chapter), then substitute for each hour of missing data using the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following:

(a) The maximum fuel flow rate the unit is capable of combusting or (b) the maximum fuel flow rate that the flowmeter can measure (i.e., upper range value of flowmeter leading to a unit).

2.4.2.2 * * *

2.4.2.3 For hours where two or more fuels are combusted, substitute the maximum hourly fuel flow rate measured and recorded by the flowmeter (or flowmeters, where fuel is recirculated) for the fuel for which data are missing at the corresponding load range recorded for each missing hour during the previous 720 hours when the unit combusted that fuel with any other fuel. For hours where no previous recorded fuel flow rate data are available for that fuel during the missing data period, calculate and substitute the maximum potential flow rate of that fuel for the unit as defined in section 2.4.2.2 of this appendix.

2.4.3 * * *

66. Appendix D to part 75 is further amended by:

- Revising sections 3 through 3.2.1 and 3.2.3;
- Removing section 3.2.4;
- Revising sections 3.3 through 3.3.3;
- Redesignating section 3.4 as 3.6 and revising the first sentence; and
- Adding new sections 3.4 through 3.4.3 and sections 3.5 through 3.5.6 to read as follows:

3. Calculations

Calculate hourly SO₂ mass emission rate from combustion of oil fuel using the procedures in section 3.1 of this appendix. Calculate hourly SO₂ mass emission rate from combustion of gaseous fuel using the procedures in section 3.3 of this appendix. (Note: the SO₂ mass emission rates in sections 3.1 and 3.3 are calculated such that the rate, when multiplied by unit operating time, yields the hourly SO₂ mass emissions for a particular fuel for the unit.) Calculate hourly heat input rate for both oil and gaseous fuels using the procedures in section 3.4 of this appendix. Calculate total SO₂ mass emissions and heat input for each hour, each quarter and the year to date using the procedures under section 3.5 of this appendix. Where an oil flowmeter records volumetric flow rate, use the calculation procedures in section 3.2 of this appendix to calculate the mass flow rate of oil.

3.1 SO₂ Mass Emission Rate Calculation for Oil

3.1.1 Use Equation D-2 to calculate SO₂ mass emission rate per hour (lb/hr):

$$\text{SO}_{2\text{-rate-oil}} = 2.0 \times \text{OIL}_{\text{rate}} \times \frac{\%S_{\text{oil}}}{100.0} \quad (\text{Eq. D-2})$$

Where:

SO_{2rate-oil} = Hourly mass emission rate of SO₂ emitted from combustion of oil, lb/hr.

OIL_{rate} = Mass rate of oil consumed per hr during combustion, lb/hr.

%S_{oil} = Percentage of sulfur by weight measured in the sample.

2.0 = Ratio of lb SO₂/lb S.

3.1.2 Record the SO₂ mass emission rate from oil for each hour that oil is combusted.

3.2 Mass Flow Rate Calculation for Volumetric Oil Flowmeters

3.2.1 Where the oil flowmeter records volumetric flow rate rather than mass flow rate, calculate and record the oil mass flow rate for each hourly period using hourly oil

flow rate measurements and the density or specific gravity of the oil sample.

* * * * *

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.6 of this appendix, use Equation D-3 to calculate the rate of the mass of oil consumed (in lb/hr):

$$\text{OIL}_{\text{rate}} = V_{\text{oil-rate}} \times D_{\text{oil}} \quad (\text{Eq. D-3})$$

Where:

OIL_{rate} = Mass rate of oil consumed per hr, lb/hr.

V_{oil-rate} = Volume rate of oil consumed per hr, measured in scf/hr, gal/hr, barrels/hr, or m³/hr.

D_{oil} = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m³.

3.3 SO₂ Mass Emission Rate Calculation for Gaseous Fuels

3.3.1 Use Equation D-4 to calculate the SO₂ mass emission rate when using the optional gas sampling and analysis procedures in sections 2.3.1 and 2.3.2 of this appendix, or the required gas sampling and analysis procedures in section 2.3.3 of this appendix. Total sulfur content of a fuel must be determined using the procedures of 2.3.3.1.2 of this appendix:

$$\text{SO}_{2\text{rate-gas}} = \left(\frac{2}{7000} \right) \times \text{GAS}_{\text{rate}} \times S_{\text{gas}} \quad (\text{Eq. D-4})$$

Where:

$\text{SO}_{2\text{rate-gas}}$ = Hourly mass rate of SO_2 emitted due to combustion of gaseous fuel, lb/hr.

GAS_{rate} = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.

S_{gas} = Sulfur content of gaseous fuel, in grain/100 scf.

2.0 = Ratio of lb SO_2 /lb S.

7000 = Conversion of grains/100 scf to lb/100 scf.

3.3.2 Use Equation D-5 to calculate the SO_2 mass emission rate when using a default emission rate from section 2.3.1.1 or 2.3.2.1.1 of this appendix:

$$\text{SO}_{2\text{rate}} = \text{ER} \times \text{HI}_{\text{rate}} \quad (\text{Eq. D-5})$$

where:

$\text{SO}_{2\text{rate}}$ = Hourly mass emission rate of SO_2 from combustion of a gaseous fuel, lb/hr.

ER = SO_2 emission rate from section 2.3.1.1 or 2.3.2.1.1, of this appendix, lb/mmBtu.

HI_{rate} = Hourly heat input rate of a gaseous fuel, calculated using procedures in section 3.4.1 of this appendix, in mmBtu/hr.

3.3.3 Record the SO_2 mass emission rate for each hour when the unit combusts a gaseous fuel.

3.4 Calculation of Heat Input Rate

3.4.1 Heat Input Rate for Gaseous Fuels

(a) Determine total hourly gas flow or average hourly gas flow rate with a fuel flowmeter in accordance with the requirements of section 2.1 of this appendix and the fuel GCV in accordance with the requirements of section 2.3.4 of this appendix. If necessary perform the 720-hour test under section 2.3.5 to determine the appropriate fuel GCV sampling frequency.

(b) Then, use Equation D-6 to calculate heat input rate from gaseous fuels for each hour.

$$\text{HI}_{\text{rate-gas}} = \frac{\text{GAS}_{\text{rate}} \times \text{GCV}_{\text{gas}}}{10^6} \quad (\text{Eq. D-6})$$

Where:

$\text{HI}_{\text{rate-gas}}$ = Hourly heat input rate from combustion of the gaseous fuel, mmBtu/hr.

GAS_{rate} = Average volumetric flow rate of fuel, for the portion of the hour in which the unit operated, 100 scf/hr.

GCV_{gas} = Gross calorific value of gaseous fuel, Btu/hr.

10^6 = Conversion of Btu to mmBtu.

(c) Note that when fuel flow is measured on an hourly totalized basis (e.g. a fuel flowmeter reports totalized fuel flow for each hour), before Equation D-6 can be used, the total hourly fuel usage must be converted from units of 100 scf to units of 100 scf/hr using Equation D-7:

$$\text{GAS}_{\text{rate}} = \frac{\text{GAS}_{\text{unit}}}{t} \quad (\text{Eq. D-7})$$

Where:

GAS_{rate} = Average volumetric flow rate of fuel for the portion of the hour in which the unit operated, 100 scf/hr.

GAS_{unit} = Total fuel combusted during the hour, 100 scf.

t = Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

3.4.2 Heat Input Rate From the Combustion of Oil

(a) Determine total hourly oil flow or average hourly oil flow rate with a fuel flowmeter, in accordance with the requirements of section 2.1 of this appendix. Determine oil GCV according to the requirements of section 2.2 of this appendix.

Then, use Equation D-8 to calculate hourly heat input rate from oil for each hour:

$$\text{HI}_{\text{rate-oil}} = \text{OIL}_{\text{rate}} \frac{\text{GCV}_{\text{oil}}}{10^6} \quad (\text{Eq. D-8})$$

Where:

$\text{HI}_{\text{rate-oil}}$ = Hourly heat input rate from combustion of oil, mmBtu/hr.

OIL_{rate} = Mass rate of oil consumed per hour, as determined using procedures in section 3.2.3 of this appendix, in lb/hr, tons/hr, or kg/hr.

GCV_{oil} = Gross calorific value of oil, Btu/lb, Btu/ton, Btu/kg.

10^6 = Conversion of Btu to mmBtu.

(b) Note that when fuel flow is measured on an hourly totalized basis (e.g., a fuel flowmeter reports totalized fuel flow for each hour), before equation D-8 can be used, the total hourly fuel usage must be converted from units of lb to units of lb/hr, using equation D-9:

$$\text{OIL}_{\text{rate}} = \frac{\text{OIL}_{\text{unit}}}{t} \quad (\text{Eq. D-9})$$

Where:

$$\text{GAS}_{\text{unit}} = \text{GAS}_{\text{meter}} \left(\frac{U_{\text{output}}}{\sum_{\text{all-units}} U_{\text{output}}} \right) \quad (\text{Eq. D-10})$$

Where:

GAS_{unit} = Gas flow apportioned to a unit, 100 scf.

$\text{GAS}_{\text{meter}}$ = Total gas flow through the fuel flowmeter, 100 scf.

U_{output} = Total unit output, MW or klb/hr.

OIL_{rate} = Average fuel flow rate for the portion of the hour which the unit operated in lb/hr.

OIL_{unit} = Total fuel combusted during the hour, lb.

t = Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

3.4.3 Apportioning Heat Input Rate to Multiple Units

(a) Use the procedure in this section to apportion hourly heat input rate to two or more units using a single fuel flowmeter which supplies fuel to the units. (This procedure is not applicable to units calculating NO_x mass emissions using the provisions of subpart H of this part.) The designated representative may also petition the Administrator under § 75.66 to use this apportionment procedure to calculate SO_2 and CO_2 mass emissions.

(b) Determine total hourly fuel flow or flow rate through the fuel flowmeter supplying gas or oil fuel to the units. Convert fuel flow rates to units of 100 scf for gaseous fuels or to lb for oil, using the procedures of this appendix. Apportion the fuel to each unit separately based on hourly output of the unit in MW, or 1000 lb of steam/hr (klb/hr) using Equation D-10 or D-11, as applicable:

$$OIL_{unit} = OIL_{meter} \left(\frac{U_{output}}{\sum_{all-units} U_{output}} \right) \quad (Eq. D-11)$$

Where:

OIL_{unit} = Oil flow apportioned to a unit, lb.

OIL_{meter} = Total oil flow through the fuel flowmeter, lb.

U_{output} = Total unit output in either MW_e or klb/hr.

(c) Use the total apportioned fuel flow calculated from Equation D-10 or D-11 to calculate the hourly unit heat input rate, using Equations D-6 and D-7 (for gas) or Equations D-8 and D-9 (for oil).

3.5 Conversion of Hourly Rates to Hourly, Quarterly and Year to Date Totals

3.5.1 Hourly SO_2 Mass Emissions From the Combustion of All Fuels

Determine the total mass emissions for each hour from the combustion of all fuels using Equation D-12:

$$M_{SO_2-hr} = \sum_{all-fuels} SO_{2-rate-i} t_i \quad (Eq. D-12)$$

Where:

M_{SO_2-hr} = Total mass of SO_2 emissions from all fuels combusted during the hour, lb.

$SO_{2-rate-i}$ = SO_2 mass emission rate for each type of gas or oil fuel combusted during the hour, lb/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

3.5.2 Quarterly Total SO_2 Mass Emissions

Sum the hourly SO_2 mass emissions in lb as determined from Equation D-12 for all hours in a quarter using Equation D-13:

$$M_{SO_2-qtr} = \frac{1}{2000} \sum_{all-hours-in-qtr} M_{SO_2-hr} \quad (Eq. D-13)$$

Where:

M_{SO_2-qtr} = Total mass of SO_2 emissions from all fuels combusted during the quarter, tons.

M_{SO_2-hr} = Hourly SO_2 mass emissions determined using Equation D-12, lb.
2000 = Conversion factor from lb to tons.

3.5.3 Year to Date SO_2 Mass Emissions

Calculate and record SO_2 mass emissions in the year to date using Equation D-14:

$$M_{SO_2-YTD} = \sum_{q=1}^{current-quarter} M_{SO_2-qtr} \quad (Eq. D-14)$$

Where:

M_{SO_2-YTD} = Total SO_2 mass emissions for the year to date, tons.

M_{SO_2-qtr} = Total SO_2 mass emissions for the quarter, tons.

3.5.4 Hourly Total Heat Input from the Combustion of all Fuels

Determine the total heat input in mmBtu for each hour from the combustion of all fuels using Equation D-15:

$$HI_{hr} = \sum_{all-fuels} HI_{rate-i} t_i \quad (Eq. D-15)$$

Where:

HI_{hr} = Total heat input from all fuels combusted during the hour, mmBtu.

HI_{rate-i} = Heat input rate for each type of gas or oil combusted during the hour, mmBtu/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

3.5.5 Quarterly Heat Input

Sum the hourly heat input values determined from equation D-15 for all hours in a quarter using Equation D-16:

$$HI_{qtr} = \frac{1}{2000} \sum_{all-hours-in-qtr} HI_{hr} \quad (Eq. D-16)$$

Where:

HI_{qtr} = Total heat input from all fuels combusted during the quarter, mmBtu.

HI_{hr} = Hourly heat input determined using Equation D-15, mmBtu.

3.5.6 Year-to-Date Heat Input

Calculate and record the total heat input in the year to date using Equation D-17.

$$HI_{YTD} = \sum_{q=1}^{current-quarter} HI_{qtr} \quad (Eq. D-17)$$

HI_{YTD} = Total heat input for the year to date, mmBtu.

HI_{qtr} = Total heat input for the quarter, mmBtu.

3.6 Records and Reports

Calculate and record quarterly and cumulative SO_2 mass emissions and heat input for each calendar quarter using the procedures and equations of section 3.5 of this appendix. * * *

67. Appendix E to part 75 is amended by revising sections 2.4.2, 2.4.3, 2.4.4, 2.5.4 and 2.5.5 to read as follows:

Appendix E to Part 75—Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units

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2. Procedure

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2.4 Procedures for Determining Hourly NO_x Emission Rate

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2.4.2 Use the graph of the baseline correlation results (appropriate for the fuel or fuel combination) to determine the NO_x emissions rate (lb/mmBtu) corresponding to the heat input rate (mmBtu/hr). Input this correlation into the data acquisition and handling system for the unit. Linearly interpolate to 0.1 mmBtu/hr heat input rate and 0.01 lb/mmBtu NO_x (0.001 lb/mmBtu NO_x after April 1, 2000). For each type of fuel, calculate NO_x emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.

2.4.3 To determine the NO_x emission rate for a unit co-firing fuels that has not been tested for that combination of fuels, interpolate between the NO_x emission rate for each fuel as follows. Determine the heat input rate for the hour (in mmBtu/hr) for each fuel and select the corresponding NO_x emission rate for each fuel on the appropriate graph. (When a fuel is combusted for a partial

hour, determine the fuel usage time for each fuel and determine the heat input rate from each fuel as if that fuel were combusted at that rate for the entire hour in order to select the corresponding NO_x emission rate.) Calculate the total heat input to the unit in mmBtu for the hour from all fuel combusted using Equation E-1. Calculate a Btu-weighted average of the emission rates for all fuels using Equation E-2 of this appendix. For each type of fuel, calculate NO_x emission rate using the baseline correlation results from the most recent test with that fuel,

beginning with the date and hour of the completion of the most recent test.

2.4.4 For each hour, record the critical quality assurance parameters, as identified in the monitoring plan, and as required by section 2.3 of this appendix from the date and hour of the completion of the most recent test for each type of fuel.

2.5 Missing Data Procedures

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2.5.4 Substitute missing data from a fuel flowmeter using the procedures in section 2.4.2 of appendix D to this part.

2.5.5 Substitute missing data for gross calorific value of fuel using the procedures in sections 2.4.1 of appendix D to this part.

68. Appendix E to part 75 is further amended by revising sections 3.1, 3.3.1, and 3.3.4 to read as follows:

3. Calculations

3.1 Heat Input

Calculate the total heat input by summing the product of heat input rate and fuel usage time of each fuel, as in the following equation:

$$H_T = HI_{fuel1}t_1 + HI_{fuel2}t_2 + HI_{fuel3}t_3 + \dots + HI_{lastfuel}t_{last} \quad (\text{Eq. E-1})$$

Where:

H_T = Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu.

HI_{fuel 1,2,3,...last} = Heat input rate from each fuel, in mmBtu/hr as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr.

t_{1,2,3,...last} = Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)).

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3.3 * * *

3.3.1 Conversion from Concentration to Emission Rate

Convert the NO_x concentrations (ppm) and O₂ concentrations to NO_x emission rates (to the nearest 0.01 lb/mmBtu for tests performed prior to April 1, 2000, or to the nearest 0.001 lb/mmBtu for tests performed on and after April 1, 2000), according to the appropriate one of the following equations: F-5 in appendix F to this part for dry basis concentration measurements or 19-3 in Method 19 of appendix A to part 60 of this chapter for wet basis concentration measurements.

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3.3.4 Average NO_x Emission Rate During Co-firing of Fuels

$$E_h = \frac{\sum_{f=1}^{\text{all fuels}} (E_f \times HI_f t_f)}{H_T} \quad (\text{Eq. E-2})$$

where:

E_h = Hourly SO₂ mass emission rate during unit operation, lb/hr.

K = 1.660 × 10⁻⁷ for SO₂, (lb/scf)/ppm.

C_{hp} = Hourly average SO₂ concentration during unit operation, ppm (dry).

Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

Where:

E_h = NO_x emission rate for the unit for the hour, lb/mmBtu.

E_f = NO_x emission rate for the unit for a given fuel at heat input rate HI_f, lb/mmBtu.

HI_f = Heat input rate for the hour for a given fuel, during the fuel usage time, as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr.

H_T = Total heat input for all fuels for the hour from Equation E-1.

t_f = Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)).

Note: For hours where a fuel is combusted for only part of the hour, use the fuel flow rate or mass flow rate during the fuel usage time, instead of the total fuel flow or mass flow during the hour, when calculating heat input rate using Equation F-19 or F-20.

69. Appendix F to part 75 is amended by revising sections 2, 2.1, 2.2, 2.3, and 2.4 to read as follows:

Appendix F to Part 75—Conversion Procedures

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2. Procedures for SO₂ Emissions

Use the following procedures to compute hourly SO₂ mass emission rate (in lb/hr) and quarterly and annual SO₂ total mass emissions (in tons). Use the procedures in Method 19 in appendix A to part 60 of this chapter to compute hourly SO₂ emission rates (in lb/mmBtu) for qualifying Phase I

$$E_h = K C_{hp} Q_{hs} \frac{(100 - \%H_2O)}{100} \quad (\text{Eq. F-2})$$

%H₂O = Hourly average stack moisture content during unit operation, percent by volume.

2.3 Use the following equations to calculate total SO₂ mass emissions for each calendar quarter (Equation F-3) and for each calendar year (Equation F-4), in tons:

technologies. When computing hourly SO₂ emission rate in lb/mmBtu, a minimum concentration of 5.0 percent CO₂ and a maximum concentration of 14.0 percent O₂ may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO₂ is less than 5.0 percent CO₂ or the hourly average concentration of O₂ is greater than 14.0 percent O₂.

2.1 When measurements of SO₂ concentration and flow rate are on a wet basis, use the following equation to compute hourly SO₂ mass emission rate (in lb/hr):

$$E_h = K C_h Q_h \quad (\text{Eq. F-1})$$

Where:

E_h = Hourly SO₂ mass emission rate during unit operation, lb/hr.

K = 1.660 × 10⁻⁷ for SO₂, (lb/scf)/ppm.

C_h = Hourly average SO₂ concentration during unit operation, stack moisture basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, stack moisture basis, scfh.

2.2 When measurements by the SO₂ pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute hourly SO₂ mass emission rate (in lb/hr):

$$E_q = \frac{\sum_{h=1}^n E_h t_h}{2000} \quad (\text{Eq. F-3})$$

Where:

E_q = Quarterly total SO₂ mass emissions, tons.

E_h = Hourly SO₂ mass emission rate, lb/hr.

t_h = Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
 n = Number of hourly SO₂ emissions values during calendar quarter.
 2000 = Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^4 E_q \quad (\text{Eq. F-4})$$

Where:

E_a = Annual total SO₂ mass emissions, tons.
 E_q = Quarterly SO₂ mass emissions, tons.
 q = Quarters for which E_q are available during calendar year.

2.4 Round all SO₂ mass emission rates and totals to the nearest tenth.

70. Appendix F to part 75 is further amended by revising sections 3.3.2, 3.3.3, 3.3.4, 3.4, and 3.5 to read as follows:

3. Procedures for NO_x Emission Rate

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3.3 * * *

3.3.2 E = Pollutant emissions during unit operation, lb/mmBtu.

3.3.3 C_h = Hourly average pollutant concentration during unit operation, ppm.

3.3.4 %O₂, %CO₂ = Oxygen or carbon dioxide volume during unit operation (expressed as percent O₂ or CO₂). A minimum concentration of 5.0 percent CO₂ and a maximum concentration of 14.0 percent O₂ may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO₂ is < 5.0 percent CO₂ or the hourly average concentration of O₂ is > 14.0 percent O₂. A minimum concentration of 1.0 percent CO₂ and a maximum concentration of 19.0 percent O₂ may be substituted for measured diluent gas concentration values at stationary gas turbines during hours when the hourly average concentration of CO₂ is < 1.0 percent CO₂ or the hourly average concentration of O₂ is > 19.0 percent O₂.

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3.4 Use the following equations to calculate the average NO_x emission rate for each calendar quarter (Equation F-9) and the average emission rate for the calendar year (Equation F-10), in lb/mmBtu:

$$E_q = \sum_{i=1}^n \frac{E_i}{n} \quad (\text{Eq. F-9})$$

Where:

E_q = Quarterly average NO_x emission rate, lb/mmBtu.
 E_i = Hourly average NO_x emission rate during unit operation, lb/mmBtu.
 n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^m \frac{E_i}{m} \quad (\text{Eq. F-10})$$

Where:

E_a = Average NO_x emission rate for the calendar year, lb/mmBtu.
 E_i = Hourly average NO_x emission rate during unit operation, lb/mmBtu.
 m = Number of hourly rates for which E_i is available in the calendar year.

3.5 Round all NO_x emission rates to the nearest 0.01 lb/mmBtu prior to April 1, 2000, and to the nearest 0.001 lb/mmBtu on and after April 1, 2000.

71. Appendix F to part 75 is further amended by revising sections 4.1, 4.2, 4.3, 4.4, and 4.4.1 to read as follows:

4. Procedures for CO₂ Mass Emissions

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4.1 When CO₂ concentration is measured on a wet basis, use the following equation to calculate hourly CO₂ mass emissions rates (in tons/hr):

$$E_h = K C_h Q_h \quad (\text{Eq. F-11})$$

Where:

E_h = Hourly CO₂ mass emission rate during unit operation, tons/hr.
 $K = 5.7 \times 10^{-7}$ for CO₂, (tons/scf) /%CO₂.
 C_h = Hourly average CO₂ concentration during unit operation, wet basis, percent CO₂. For boilers, a minimum concentration of 5.0 percent CO₂ may be substituted for the measured concentration when the hourly average concentration of CO₂ is < 5.0 percent CO₂, provided that this minimum concentration of 5.0 percent CO₂ is also used in the calculation of heat input for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO₂ may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO₂ is < 1.0 percent CO₂, provided that this minimum concentration of 1.0 percent CO₂ is also used in the calculation of heat input for that hour.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9} \quad (\text{Eq. F-14a})$$

4.2 When CO₂ concentration is measured on a dry basis, use Equation F-2 to calculate the hourly CO₂ mass emission rate (in tons/hr) with a K-value of 5.7×10^{-7} (tons/scf) percent CO₂, where E_h = hourly CO₂ mass emission rate, tons/hr and C_{hp} = hourly average CO₂ concentration in flue, dry basis, percent CO₂.

4.3 Use the following equations to calculate total CO₂ mass emissions for each calendar quarter (Equation F-12) and for each calendar year (Equation F-13):

$$E_{CO_{2q}} = \sum_{h=1}^{H_R} E_h t_h \quad (\text{Eq. F-12})$$

Where:

$E_{CO_{2q}}$ = Quarterly total CO₂ mass emissions, tons.

E_h = Hourly CO₂ mass emission rate, tons/hr.
 t_h = Unit operating time, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

H_R = Number of hourly CO₂ mass emission rates available during calendar quarter.

$$E_{CO_{2a}} = \sum_{q=1}^4 E_{CO_{2q}} \quad (\text{Eq. F-13})$$

Where:

$E_{CO_{2a}}$ = Annual total CO₂ mass emission, tons.
 $E_{CO_{2q}}$ = Quarterly total CO₂ mass emissions, tons.

q = Quarters for which $E_{CO_{2q}}$ are available during calendar year.

4.4 For an affected unit, when the owner or operator is continuously monitoring O₂ concentration (in percent by volume) of flue gases using an O₂ monitor, use the equations and procedures in section 4.4.1 and 4.4.2 of this appendix to determine hourly CO₂ mass emissions (in tons).

4.4.1 Use appropriate F and F_c factors from section 3.3.5 of this appendix in one of the following equations (as applicable) to determine hourly average CO₂ concentration of flue gases (in percent by volume):

CO_{2d} = Hourly average CO₂ concentration during unit operation, percent by volume, dry basis.

F, F_c = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O₂ in ambient air.

O_{2d} = Hourly average O₂ concentration during unit operation, percent by volume, dry basis. For boilers, a maximum concentration of 14.0 percent O₂ may be substituted for the measured concentration when the hourly average concentration of O₂ is > 14.0 percent O₂, provided that this maximum concentration of 14.0 percent O₂ is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O₂ may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O₂ is > 19.0 percent O₂, provided that this maximum concentration of 19.0 percent O₂ is also used in the calculation of heat input for that hour.

$$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[20.9 \left(\frac{100 - \%H_2O}{100} \right) - O_{2w} \right] \quad (\text{Eq. F-14b})$$

Where:

CO_{2w} = Hourly average CO₂ concentration during unit operation, percent by volume, wet basis.

O_{2w} = Hourly average O₂ concentration during unit operation, percent by volume, wet basis. For boilers, a maximum concentration of 14.0 percent O₂ may be substituted for the measured concentration when the hourly average concentration of O₂ is > 14.0 percent O₂, provided that this maximum concentration of 14.0 percent O₂ is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O₂ may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O₂ is > 19.0 percent O₂, provided that this maximum concentration of 19.0 percent O₂ is also used in the calculation of heat input for that hour.

F, F_c = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O₂ in ambient air.

%H₂O = Moisture content of gas in the stack, percent.

* * * * *

72. Appendix F to part 75 is amended by revising sections 5 through 5.2.4; adding sections 5.3 through 5.3.2; revising sections

5.5, 5.5.1 and 5.5.2; and by adding new sections 5.6 through 5.6.2 and 5.7 and by removing and revising section 5.4 to read as follows:

5. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

5.1 Calculate and record heat input rate to an affected unit on an hourly basis, except as provided in sections 5.5 through 5.5.7. The owner or operator may choose to use the provisions specified in § 75.16(e) or in section 2.1.2 of appendix D to this part in conjunction with the procedures provided in sections 5.6 through 5.6.2 to apportion heat input among each unit using the common stack or common pipe header.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O₂ or CO₂) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

5.2.1 When measurements of CO₂ concentration are on a wet basis, use the following equation:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100F_c} \right] \left(\frac{\%CO_{2d}}{100} \right) \quad (\text{Eq. F-16})$$

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100} \quad (\text{Eq. F-15})$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

%CO_{2w} = Hourly concentration of CO₂ during unit operation, percent CO₂ wet basis.

For boilers, a minimum concentration of 5.0 percent CO₂ may be substituted for the measured concentration when the hourly average concentration of CO₂ is < 5.0 percent CO₂, provided that this minimum concentration of 5.0 percent CO₂ is also used in the calculation of CO₂ mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO₂ may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO₂ is < 1.0 percent CO₂, provided that this minimum concentration of 1.0 percent CO₂ is also used in the calculation of CO₂ mass emissions for that hour.

5.2.2 When measurements of CO₂ concentration are on a dry basis, use the following equation:

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-Factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2d}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 dry basis. For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2 , provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2 , provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour.

$\%H_2O$ = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{[(20.9/100)(100 - \%H_2O) - \%O_{2w}]}{20.9} \quad (\text{Eq. F-17})$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

$\%O_{2w}$ = Hourly concentration of O_2 during unit operation, percent O_2 wet basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2 , provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2 , provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour.

$\%H_2O$ = Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O_2 concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100 F} \right] \left[\frac{(20.9 - \%O_{2d})}{20.9} \right] \quad (\text{Eq. F-18})$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

%H₂O = Moisture content of the stack gas, percent.

%O_{2d} = Hourly concentration of O₂ during unit operation, percent O₂ dry basis. For boilers, a maximum concentration of 14.0 percent O₂ may be substituted for the measured concentration when the hourly average concentration of O₂ is > 14.0 percent O₂, provided that this maximum concentration of 14.0 percent O₂ is also used in the calculation of CO₂ mass emissions for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O₂ may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O₂ is > 19.0 percent O₂, provided that this maximum concentration of 19.0 percent O₂ is also used in the calculation of CO₂ mass emissions for that hour.

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

5.3.1 Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_q = \sum_{\text{hour}=1}^n HI_i t_i \quad (\text{Eq. F-18a})$$

Where:

HI_q = Total heat input for the quarter, mmBtu.

HI_i = Hourly heat input rate during unit operation, using Equation F-15, F-16, F-17, or F-18, mmBtu/hr.

t_i = Hourly operating time for the unit or common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

5.3.2 Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q \quad (\text{Eq. F-18b})$$

Where:

HI_c = Total heat input for the year to date, mmBtu.

HI_q = Total heat input for the quarter, mmBtu.

5.4 [Reserved]

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO₂ emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_x mass emissions under a State or federal NO_x mass emission reduction program.

5.5.1(a) When the unit is combusting oil, use the following equation to calculate hourly heat input rate:

$$HI_o = M_o \frac{GCV_o}{10^6} \quad (\text{Eq. F-19})$$

Where:

HI_o = Hourly heat input rate from oil, mmBtu/hr.

M_o = Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.

GCV_o = Gross calorific value of oil, as measured by ASTM D240-87 (Reapproved 1991), ASTM D2015-91, or ASTM D2382-88 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (incorporated by reference under § 75.6).

10⁶ = Conversion of Btu to mmBtu.

(b) When performing oil sampling and analysis solely for the purpose of the missing

data procedures in § 75.36, oil samples for measuring GCV may be taken weekly, and the procedures specified in appendix D to this part for determining the mass rate of oil consumed per hour are optional.

5.5.2 When the unit is combusting gaseous fuels, use the following equation to calculate heat input rate from gaseous fuels for each hour:

$$HI_g = \frac{(Q_g \times GCV_g)}{10^6} \quad (\text{Eq. F-20})$$

Where:

HI_g = Hourly heat input rate from gaseous fuel, mmBtu/hour.

Q_g = Metered flow rate of gaseous fuel combusted during unit operation, hundred cubic feet.

GCV_g = Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826-88, ASTM D3588-91, ASTM D4891-89, GPA Standard 2172-86 "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis," or GPA Standard 2261-90 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," Btu/100 scf (incorporated by reference under § 75.6).

10⁶ = Conversion of Btu to mmBtu.

* * * * *

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts should apportion the heat input rate using the following equation:

$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{MW_i t_i}{\sum_{i=1}^n MW_i t_i} \right] \quad (\text{Eq. F-21a})$$

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CS} = Heat input rate at the common stack or pipe, mmBtu/hr.

MW_i = Gross electrical output, MWe.

t_i = Operating time at a particular unit, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS} = Operating time at common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack.

i = Designation of a particular unit.

5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by

apportioning the heat input rate monitored at a common stack or common pipe using steam

load should apportion the heat input rate using the following equation:

$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{SF_i t_i}{\sum_{i=1}^n SF_i t_i} \right] \quad (\text{Eq. F-21b})$$

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CS} = Heat input rate at the common stack or pipe, mmBtu/hr.

SF = Gross steam load, lb/hr.

t_i = Operating time at a particular unit, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS} = Operating time at common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack.

i = Designation of a particular unit.

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes should sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^n HI_s t_s}{t_{Unit}} \quad (\text{Eq. F-21c})$$

Where:

HI_{Unit} = Heat input rate for a unit, mmBtu/hr.

HI_s = Heat input rate for each stack or duct leading from the unit, mmBtu/hr.

t_{Unit} = Operating time for the unit, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_s = Operating time during which the unit is exhausting through the stack or duct, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

73. Appendix F is further amended by revising section 7 to read as follows:

7. Procedures for SO_2 Mass Emissions at Units With SO_2 Continuous Emission Monitoring Systems During the Combustion of Pipeline Natural Gas or Natural Gas

The owner or operator shall use the following equation to calculate hourly SO_2 mass emissions as allowed for units with SO_2 continuous emission monitoring systems if, during the combustion of gaseous fuel that meets the definition of pipeline natural gas

or natural gas in § 72.2 of this chapter, SO_2 emissions are determined in accordance with § 75.11(e)(1).

$$E_h = (ER) (HI) \quad (\text{Eq. F-23})$$

Where:

E_h = Hourly SO_2 mass emissions, lb/hr.

ER = Applicable SO_2 default emission rate from section 2.3.1.1 or 2.3.2.1.1 of appendix D to this part, lb/mmBtu.

HI = Hourly heat input, as determined using the procedures of section 5.2 of this appendix.

74. Appendix F is further amended by correcting section 8 to read as follows:

8. Procedures for NO_x Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO_x mass emissions under a State or federal NO_x mass emission reduction program must use the procedures in section 8.1, 8.2, or 8.3, as applicable, to account for hourly NO_x mass emissions, and the procedures in section 8.4 to account for quarterly, seasonal, and annual NO_x mass emissions to the extent that the provisions of subpart H of this part are adopted as requirements under such a program.

75. Appendix G to part 75 is amended by revising the paragraph defining the term " W_c " that follows Equation G-1 and by revising the paragraph defining the term " F_c " that follows Equation G-4 to read as follows:

Appendix G to Part 75—Determination of CO_2 Emissions

* * * * *

2. Procedures for Estimating CO_2 Emissions From Combustion

* * * * *

2.1 * * *

(Eq. G-1)

Where:

* * * * *

W_c = Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates. Collect at least one fuel sample during each week that the unit combusts coal, one sample per each shipment or delivery for oil and diesel fuel, one fuel sample for each delivery for gaseous fuel in lots, one sample per day or per hour (as applicable) for each gaseous fuel that is required to be sampled daily or hourly for gross calorific value under section 2.3.5.6 of appendix D to this part, and one sample per month for each gaseous fuel that is required to be sampled monthly for gross calorific value under section 2.3.4.1 or 2.3.4.2 of appendix D to this part. Collect coal samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during the week. Determine the carbon content of each fuel sampling using one of the following methods: ASTM D3178-89 or ASTM D5373-93 for coal; ASTM D5291-92 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil, or computations based upon ASTM D3238-90 and either ASTM D2502-87 or ASTM D2503-82 (Reapproved 1987) for oil; and computations based on ASTM D1945-91 or ASTM D1946-90 for gas. Use daily fuel feed rates from company records for all fuels and the carbon content of the most recent fuel sample under this section to determine tons of carbon per day from combustion of each fuel. (All ASTM methods are incorporated by reference under § 75.6.) Where more than one fuel is combusted during a calendar day, calculate total tons of carbon for the day from all fuels.

* * * * *

2.3 * * *

(Eq. G-4)

Where:

* * * * *

F_c = Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1,240 scf/mmBtu for crude, residual, or distillate oil; and calculated according to the procedures in section 3.3.5 of appendix F to this part for other gaseous fuels.

* * * * *

76. Appendix G to part 75 is amended by adding new sections 5 through 5.3 to read as follows:

5. Missing Data Substitution Procedures for Fuel Analytical Data

Use the following procedures to substitute for missing fuel analytical data used to calculate CO₂ mass emissions under this appendix.

5.1 Missing Carbon Content Data Prior to 4/1/2000

Prior to April 1, 2000, follow either the procedures of this section or the procedures of section 5.2 of this appendix to substitute for missing carbon content data. On and after April 1, 2000, use the procedures of section 5.2 of this appendix to substitute for missing carbon content data, not the procedures of this section.

5.1.1 Most Recent Previous Data

Substitute the most recent, previous carbon content value available for that fuel type (gas, oil, or coal) of the same grade (for oil) or rank (for coal). To the extent practicable, use a carbon content value from the same fuel supply. Where no previous carbon content data are available for a particular fuel type or rank of coal, substitute the default carbon content from Table G-1 of this appendix.

5.1.2 [Reserved]

5.2 Missing Carbon Content Data On and After 4/1/2000

Prior to April 1, 2000, follow either the procedures of this section or the procedures of section 5.1 of this appendix to substitute for missing carbon content data. On and after April 1, 2000, use the procedures of this

section to substitute for missing carbon content data.

5.2.1 In all cases (i.e., for weekly coal samples or composite oil samples from continuous sampling, for oil samples taken from the storage tank after transfer of a new delivery of fuel, for as-delivered samples of oil, diesel fuel, or gaseous fuel delivered in lots, and for gaseous fuel that is supplied by a pipeline and sampled monthly, daily or hourly for gross calorific value) when carbon content data is missing, report the appropriate default value from Table G-1.

5.2.2 The missing data values in Table G-1 shall be reported whenever the results of a required sample of fuel carbon content are either missing or invalid. The substitute data value shall be used until the next valid carbon content sample is obtained.

TABLE G-1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Sampling technique/frequency	Missing data value
Oil and coal carbon content	All oil and coal samples, prior to April 1, 2000	Most recent, previous carbon content value available for that grade of oil, or default value, in this table.
Gas carbon content	All gaseous fuel samples, prior to April 1, 2000.	Most recent, previous carbon content value available for that type of gaseous fuel, or default value, in this table.
Default coal carbon content	All, on and after April 1, 2000	Anthracite: 90.0 percent. Bituminous: 85.0 percent. Subbituminous/Lignite: 75.0 percent.
Default oil carbon content	All, on and after April 1, 2000	90.0 percent.
Default gas carbon content	All, on and after April 1, 2000	Natural gas: 75.0 percent. Other gaseous fuels: 90.0 percent.

5.3 Gross Calorific Value Data

For a gas-fired unit using the procedures of section 2.3 of this appendix to determine CO₂ emissions, substitute for missing gross calorific value data used to calculate heat input by following the missing data procedures for gross calorific value in section 2.4 of appendix D to this part.

Appendix H to Part 75—Revised Traceability Protocol No. 1

77. Appendix H to part 75 is removed and reserved.

Appendix J to Part 75—Compliance Dates for Revised Recordkeeping Requirements and Missing Data Procedures

78. Appendix J to part 75 is removed and reserved.

[FR Doc. 99-8939 Filed 5-25-99; 8:45 am]

BILLING CODE 6560-50-U

This final rule is considered not "economically significant" as defined under Executive Order 12866 and, therefore, is not subject to Executive Order 13045.

J. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13084, the EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments, or the EPA consults with those governments. If the EPA complies by consulting, Executive Order 13084 requires the EPA to provide to the OMB, in a separately identified section of the preamble to the rule, a description of the extent of the EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires the EPA to develop an effective process permitting elected officials and other representatives of Indian tribal governments "to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities."

Today's amendments to the rule do not significantly or uniquely affect the communities of Indian tribal governments. The amendments issued today extend the compliance date for continuous web cleaning machines, and do not add any new requirements. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Continuous web cleaning machines, Halogenated solvent cleaning machines, Hazardous substances, Reporting and recordkeeping requirements.

Dated: December 4, 1998.

Carol M. Browner,
Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart T—National Emission Standards for Halogenated Solvent Cleaning

2. Section 63.460 is amended by revising paragraphs (c) and (d), and adding paragraph (g) to read as follows:

§ 63.460 Applicability and designation of source.

* * * * *

(c) Except as provided in paragraph (g) of this section, each solvent cleaning machine subject to this subpart that commences construction or reconstruction after November 29, 1993 shall achieve compliance with the provisions of this subpart immediately upon start-up or by December 2, 1994, whichever is later.

(d) Except as provided in paragraph (g) of this section, each solvent cleaning machine subject to this subpart that commenced construction or reconstruction on or before November 29, 1993 shall achieve compliance with the provisions of this subpart no later than December 2, 1997.

* * * * *

(g) Each continuous web cleaning machine subject to this subpart shall achieve compliance with the provisions of this subpart no later than December 2, 1999.

* * * * *

§ 63.470 [Removed and reserved].

3. Part 63 is amended by removing and reserving section 63.470.

[FR Doc. 98-32991 Filed 12-10-98; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72 and 73

[FRL-6201-3]

RIN 2060-AH60

Revisions to the Permits and Sulfur Dioxide Allowance System Regulations Under Title IV of the Clean Air Act: Allowance Transfer Deadline and Signature Requirements

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Title IV of the Clean Air Act (the Act), as amended by the Clean Air Act Amendments of 1990, authorizes

the Environmental Protection Agency (EPA or Agency) to establish the Acid Rain Program. The program sets emissions limitations to reduce acidic particles and deposition and their serious, adverse effects on natural resources, ecosystems, materials, visibility, and public health.

The allowance trading component of the Acid Rain Program allows utilities to achieve sulfur dioxide emissions reductions in the most cost-effective way. Allowances are traded among utilities and recorded in EPA's Allowance Tracking System for use in determining compliance at the end of each year. The Acid Rain Program's permitting and allowance trading, and emissions monitoring requirements are set forth in the "core" rules initially promulgated on January 11, 1993. This action amends certain provisions in the permitting and allowance trading rules for the purpose of improving the operation of the Allowance Tracking System and the allowance market, while still preserving the Act's environmental goals. The entities affected by this change fall under Standard Industrial Code 49 (Electric, Gas and Sanitary Services).

EFFECTIVE DATE: January 11, 1999.

ADDRESSES: *Docket.* Docket No. A-98-15, containing supporting information used in developing the proposed rule, is available for public inspection and copying between 8:30 a.m. and 3:30 p.m., Monday through Friday, at EPA's Air Docket Section, Waterside Mall, room 1500, 1st Floor, 401 M Street, S.W., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Donna Deneen, Permits and Allowance Market Branch, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street S.W., Washington, DC 20460 (202-564-9089).

SUPPLEMENTARY INFORMATION: This preamble contains all of the responses to public comments received on the revisions finalized in today's action. There is no additional background information document.

The information in this preamble is organized as follows:

- I. Affected Entities
- II. Background
- III. Public Participation
- IV. Summary of Major Comments and Responses
 - A. Allowance Transfer Deadline
 - B. Signature Requirement for Transfer Requests
 - C. Impacts of Revisions on Acid Rain Permits
- V. Administrative Requirements
 - A. Docket

- B. Executive Order 12866
- C. Executive Order 12875: Enhancing Intergovernmental Partnerships
- D. Executive Order 13084: Consultation and Coordination with Indian Tribal Governments
- E. Unfunded Mandates Act
- F. Paperwork Reduction Act
- G. Regulatory Flexibility
- H. Applicability of Executive Order 13045: Children's Health Protection
- I. National Technology Transfer and Advancement Act
- J. Congressional Review Act

I. Affected Entities

Entities potentially regulated by this action are fossil-fuel fired boilers or turbines that serve generators producing electricity, generate steam, or cogenerate electricity and steam. Regulated categories and entities include:

Category	Examples of regulated entities
Industry SIC 49—Electric, Gas and Sanitary Services.	Electric service providers, boilers from a wide range of industries.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria in § 72.6 and § 74.2 and the exemptions in §§ 72.7, 72.8, and 72.14 of title 40 of the Code of Federal Regulations. If you have questions regarding the applicability of this action to a particular entity, consult the persons listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

II. Background

On January 11, 1993, EPA promulgated the "core" regulations that implemented the major provisions of title IV of the Clean Air Act (CAA or the Act), as amended on November 15, 1990, including the Permits rule (40 CFR part 72) and the Sulfur Dioxide Allowance System rule (40 CFR part 73). Since promulgation, these rules have been applied to three compliance years, 1995, 1996, and 1997, for which affected units were required to meet the annual allowance holding requirements established by the rules. During this time, the Agency gained experience in implementing the requirements and also discovered ways that the operation of the Allowance Tracking System and allowance market could be improved.

On August 3, 1998, EPA proposed changes to certain provisions in 40 CFR parts 72 and 73 to make these improvements. (63 FR 41358 (1998)). These proposed changes were related to the allowance transfer deadline, compliance determinations, and the signature requirements for allowance transfer requests.¹

The Agency received seven comment letters on the proposed revisions. All of the commenters strongly supported the revision to the allowance transfer deadline and the clarification of the signature requirements for allowance transfer requests. Today's action, therefore, finalizes these two revisions as proposed. EPA is not taking action at this time on the third proposed revision, which would allow deduction of allowances from other unit accounts after the allowance transfer deadline and on which EPA received adverse comment.

III. Public Participation

Revisions to 40 CFR parts 72 and 73 were proposed on August 3, 1998. (63 FR 41358). The notice invited public comments, and copies of the proposed rule were made available to interested parties.

EPA offered to hold a public hearing upon request, but no such request was made and no hearing was held. EPA did, however, receive a request to extend the comment period 15 days from September 2, 1998 to September 17, 1998. A notice granting the request was published on August 24, 1998. 63 FR 45037 (1998).

IV. Summary of Major Comments and Responses

EPA received seven comment letters regarding the proposed changes to the regulations. All of the commenters were representatives of utility companies or groups of utility companies. A copy of each comment letter received is included in the rulemaking docket.

All of the commenters supported the 30 day extension to the allowance transfer deadline and the clarification of the signature requirements on transfer forms. A summary of the comments received on these two revisions and the Agency responses are set forth in the following two sections.

A. Allowance Transfer Deadline

The "allowance transfer deadline" is the last day on which allowance transfers may be submitted to EPA for recordation in a compliance subaccount

for use in meeting a unit's sulfur dioxide (SO₂) emissions limitation requirements for the year. 40 CFR 72.2 (definition of "allowance transfer deadline"). EPA proposed to extend the allowance transfer deadline from the current date of January 30 to March 1 (or February 29 in any leap year) to reflect the Agency's experience in operating the Allowance Tracking System and the technological advances that have been made regarding the submission of continuous emissions monitoring system (CEMS) data.

Comments: All seven commenters strongly supported the proposed extension of the allowance transfer deadline to March 1 (or February 29 in any leap year). Five of the commenters reiterated the arguments EPA made in the proposal for extending the date, while the other two commenters simply acknowledged support of the change.

Response: Because EPA received only supportive comments on its proposed change to the allowance transfer deadline, EPA is extending the allowance transfer deadline to the proposed date of March 1 (or February 29 in any leap year) in today's final rule. The reasons for extending the deadline are more fully explained in the preamble to the proposed rule. 63 FR 41358.

B. Signature Requirement for Transfer Requests

Under the core rules, § 73.50(b)(1) required authorized account representatives seeking recordation of an allowance transfer to submit a request for the transfer that contains, among other things, signatures of the authorized account representatives for both the transferor and the transferee accounts. In its August 3, 1998 proposed rulemaking, the Agency proposed to add § 73.50(b)(2) to clarify that the authorized account representative for a transferee account can meet the signature requirement by submitting, along with or in advance of a transfer request from the authorized account representative for any transferor account, a signed statement identifying the accounts into which any transfer of allowances is authorized, on or after the date of EPA's receipt of the statement. Receipt by EPA of the signed statement satisfies the transferee signature requirement for all contemporaneous or subsequent transfers into accounts identified in the statement. The specific language for the statement was set forth in proposed § 73.50(b)(2).

Comments: All seven commenters strongly supported the clarification of the signature requirements for transfer forms. One commenter noted that the

¹ In addition, the proposal revised § 73.34(c)(4) to eliminate the reference to the direct sales provisions, which were previously removed from part 73. 61 FR 28761, 28762 (1996).

Agency's proposal would simplify and streamline the allowance transfer process. The same commenter and one other stated that advance approval of allowance transfers would make more feasible the electronic submission of electronic transfers. The other five commenters simply acknowledged support of the revision.

Response: Because EPA received only supportive comments on its proposed revision to the signature requirements for allowance transfer requests, EPA is finalizing this rule revision (with the correction of a minor citation error in § 73.50(b)(2)(i)). The reasons for this revision are more fully explained in the preamble to the proposed rule. 63 FR 41363.

C. Impacts of Revisions on Acid Rain Permits

Today's revisions are designed so that the contents of existing acid rain permits and the State regulations required to issue acid rain permits do not have to be changed in order for the revisions to become effective. With the exception of a change in the definition of "allowance transfer deadline," all of today's revisions are made in 40 CFR part 73. As explained in the preamble to the proposed rule (63 FR 41364), it is unnecessary for State permitting authorities to revise the acid rain permits they have issued or regulations they have adopted to reflect today's final revisions to 40 CFR part 73.

Similarly, the revisions can go into effect without State permitting authorities revising acid rain permits or regulations to reflect the revised definition of "allowance transfer deadline" in 40 CFR part 72. Even if a State issued an acid rain permit before today's revision of the allowance transfer deadline becomes effective, the Agency will apply the revised deadline to the units covered by the permit in determining end-of-year compliance for all calendar years beginning with 1998. See 63 FR 41364.

While EPA will apply the revised allowance transfer deadline in § 72.2, State permitting authorities should revise their own regulations to reflect the new deadline after it is finalized. This will avoid any potential confusion on the part of regulated entities and the public as to when EPA determines end-of-year compliance.

IV. Administrative Requirements

A. Docket

A docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a

dynamic file since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to identify and locate documents readily so that they can effectively participate in the rulemaking process. Along with the preambles of the proposed and final rule (which include EPA responses to significant comments), the contents of the docket will serve as the record in case of judicial review to the extent provided in section 307(d)(7)(A) of the Act.

B. Executive Order 12866

Under Executive Order 12866 (58 FR 51735 (October 4, 1993)), the Agency must determine whether the regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Executive Order defines "significant regulatory action" as one that is likely to result in a rule that may:

- (1) Have an annual effect on the economy of \$100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;
- (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, EPA has determined that today's rule is not a "significant regulatory action."

C. Executive Order 12875: Enhancing Intergovernmental Partnerships

Under Executive Order 12875, EPA may not issue a regulation that is not required by statute and that creates a mandate upon a State, local or tribal government, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by those governments or unless EPA consults with those governments. If EPA complies by consulting, Executive Order 12875 requires EPA provide to the Office of Management and Budget a description of the extent of EPA's prior consultation with representatives of affected State, local and tribal governments, the nature of their concerns, copies of any written communications from the governments,

and a statement supporting the need to issue the regulation. In addition, Executive Order 12875 requires EPA to develop an effective process permitting elected officials and other representatives of State, local and tribal governments "to provide meaningful and timely input in the development of regulatory proposals containing significant unfunded mandates."

Today's rule does not create a new mandate on State, local or tribal governments. It modifies an existing mandate in a way that imposes no additional duties and no additional costs on these entities. Accordingly, the requirements of section 1(a) of Executive Order 12875 do not apply to this rule.

D. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments or unless EPA consults with those governments. If EPA complies by consulting, EPA must provide to the Office of Management and Budget, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected and other representatives of Indian tribal governments "to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities."

Today's rule does not significantly or uniquely effect, or impose any substantial direct compliance costs on, the communities of Indian tribal governments. The rule does not impose any enforceable duties on these entities. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

E. Unfunded Mandates Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104-4, establishes requirements for federal agencies to assess the effects of their regulatory actions on State, local,

and tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, before promulgating a proposed or final rule that includes a federal mandate that may result in expenditure by State, local, and tribal governments, in aggregate, or by the private sector, of \$100 million or more in any one year. Section 205 generally requires that, before promulgating a rule for which a written statement must be prepared, EPA must identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator explains why that alternative was not adopted. Finally, section 203 requires that, before establishing any regulatory requirements that may significantly or uniquely affect small governments, EPA must have developed a small government agency plan. The plan must provide for notifying any potentially affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Because today's rule is estimated to result in the expenditure by State, local, and tribal governments or the private sector of less than \$100 million in any one year, the Agency has not prepared a budgetary impact statement or specifically addressed the selection of the least costly, most cost-effective, or least burdensome alternative. Because small governments will not be significantly or uniquely affected by this rule, the Agency is not required to develop a plan with regard to small governments.

Today's final revisions to parts 72 and 73 will potentially reduce the burden on regulated entities by streamlining the allowance transfer process and extending the allowance transfer deadline. The revisions will not otherwise have any significant impact on State, local, and tribal governments.

F. Paperwork Reduction Act

Today's final revisions to parts 72 and 73 will not impose any new information collection burden subject to the

Paperwork Reduction Act (44 U.S.C. 3501, *et seq.*). The extension of the allowance transfer deadline does not result in any new information requirements and the revisions made to the signature requirement simply clarify EPA's existing practice of accepting the signature of the authorized account representative for a transferee account in advance of an allowance transfer form. OMB has previously approved the relevant information collection requirements contained in parts 72 and 73 under the provisions of the Paperwork Reduction Act and has assigned OMB control number 2060-0258. 58 FR 3590, 3650 (1993).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Copies of the previously approved ICR may be obtained from the Director, Regulatory Information Division; EPA; 401 M St. SW (mail code 2137); Washington, DC 20460 or by calling (202) 564-2740. Include the ICR and/or OMB number in any correspondence.

G. Regulatory Flexibility

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601, *et seq.*, generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small government jurisdictions.

As discussed above, today's final revisions will reduce the burden on regulated entities by streamlining and adding flexibility to the regulations. For these reasons, EPA has determined that this rule will not have a significant economic impact on a substantial number of small entities.

H. Applicability of Executive Order 13045: Children's Health Protection

Executive Order 13045 (62 FR 19885, April 29, 1997) applies to any rule if EPA determines (1) that the rule is economically significant as defined under Executive Order 12866, and (2) that the environmental health or safety risk addressed by the rule has a disproportionate effect on children. If the regulatory action meets both criteria, EPA must evaluate the environmental health or safety effects of the planned rule on children and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by EPA.

This final action is not subject to Executive Order 13045, because the action is not economically significant as defined by Executive Order 12866 and does not address an environmental health or safety risk having a disproportionate effect on children.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104-113, section 12(d)(15 U.S.C. 272 note), directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, or business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA requires EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

Today's final rule does not involve any technical standards that would require Agency consideration of voluntary consensus standards pursuant to section 12(d) of the NTTAA.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in

the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This rule is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective 30 days after publication in the **Federal Register**.

List of Subjects in 40 CFR Parts 72 and 73

Environmental protection, Acid rain, Administrative practice and procedure, Air pollution control, Compliance plans, Electric utilities, Penalties, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: December 4, 1998.

Carol M. Browner,
Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 72—[AMENDED]

1. The authority citation for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

2. Section 72.2 is amended by removing from the definition of "Allowance transfer deadline" the words "January 30 or, if January 30" and adding, in their place, the words "March 1 (or February 29 in any leap year) or, if such day."

PART 73—[AMENDED]

3. The authority citation for part 73 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

4. Section 73.34 is amended by removing from paragraph (c)(4) the words "or direct sale pursuant to subpart E of this part".

5. Section 73.50 is amended by redesignating paragraph (b)(2) as (b)(3) and adding new paragraph (b)(2) as follows:

§ 73.50 Scope and submission of transfers.

* * * * *

(b) * * *

(2)(i) The authorized account representative for the transferee account can meet the requirements in paragraphs (b)(1)(iii) and (iv) of this section by submitting, in a format prescribed by the Administrator, a statement signed by the authorized account representative and identifying each account into which any transfer of allowances, submitted on or after the date on which the Administrator receives such statement, is authorized. Such authorization shall be binding on

any authorized account representative for such account and shall apply to all transfers into the account that are submitted on or after such date of receipt, unless and until the Administrator receives a statement in a format prescribed by the Administrator and signed by the authorized account representative retracting the authorization for the account.

(ii) The statement under paragraph (b)(2)(i) of this section shall include the following: "By this signature, I authorize any transfer of allowances into each Allowance Tracking System account listed herein, except that I do not waive any remedies under 40 CFR part 73, or any other remedies under State or federal law, to obtain correction of any erroneous transfers into such accounts. This authorization shall be binding on any authorized account representative for such account unless and until a statement signed by the authorized account representative retracting this authorization for the account is received by the Administrator."

* * * * *

[FR Doc. 98-32990 Filed 12-10-98; 8:45 am]
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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 971015246-7293-02; I.D. 120798A]

Fisheries of the Northeastern United States; Summer Flounder Fishery; Commercial Quota Harvested for Virginia

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Commercial quota harvest.

SUMMARY: NMFS announces that the summer flounder commercial quota available to the Commonwealth of Virginia has been harvested. Vessels issued a commercial Federal fisheries permit for the summer flounder fishery may not land summer flounder in Virginia for the remainder of calendar year 1998, unless additional quota becomes available through a transfer. Regulations governing the summer flounder fishery require publication of this notification to advise the Commonwealth of Virginia that the quota has been harvested and to advise vessel permit holders and dealer permit

holders that no commercial quota is available for landing summer flounder in Virginia.

DATES: Effective 0001 hours, December 9, 1998, through December 31, 1998.

FOR FURTHER INFORMATION CONTACT: Paul H. Jones, Fishery Policy Analyst, (978) 281-9273.

SUPPLEMENTARY INFORMATION:

Regulations governing the summer flounder fishery are found at 50 CFR part 648. The regulations require annual specification of a commercial quota that is apportioned among the coastal states from North Carolina through Maine. The process to set the annual commercial quota and the percent allocated to each state are described in § 648.100.

The initial total commercial quota for summer flounder for the 1998 calendar year was set equal to 11,105,636 lb (5,037,432 kg) (62 FR 66304, December 18, 1997). The percent allocated to vessels landing summer flounder in Virginia is 21.31676 percent, or 2,368,569 lb (1,074,365 kg).

Section 648.100(e)(4) stipulates that any overages of commercial quota landed in any state be deducted from that state's annual quota for the following year. In the calendar year 1997, a total of 2,305,985 lb (1,045,977 kg) were landed in Virginia, creating a 11,192 lb (5,077 kg) overage that was deducted from the amount allocated for landings in the state during 1998 (63 FR 23227, April 28, 1998). The resulting quota for Virginia is 2,357,377 lb (1,069,288 kg).

Section 648.101(b) requires the Administrator, Northeast Region, NMFS (Regional Administrator), to monitor state commercial quotas and to determine when a state's commercial quota is harvested. The Regional Administrator is further required to publish notification in the **Federal Register** advising a state and notifying Federal vessel and dealer permit holders that, effective upon a specific date, the state's commercial quota has been harvested and no commercial quota is available for landing summer flounder in that state. The Regional Administrator has determined, based upon dealer reports and other available information, that the State of Virginia has attained its quota for 1998.

The regulations at § 648.4(b) provide that Federal permit holders agree as a condition of the permit not to land summer flounder in any state that the Regional Administrator has determined no longer has commercial quota available. Therefore, effective 0001 hours, December 9, 1998, further landings of summer flounder in Virginia by vessels holding commercial Federal

(21) *Mobile source*. A motor vehicle, nonroad engine or nonroad vehicle, where:

(i) *Motor vehicle* means any self-propelled vehicle designed for transporting persons or property on a street or highway;

(ii) *Nonroad engine* means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 111 or section 202 of the CAA;

(iii) *Nonroad vehicle* means a vehicle that is powered by a nonroad engine and that is not a motor vehicle or a vehicle used solely for competition.

(22) *Ozone season*. The period May 1 through September 30 of a year.

(23) *Physical address*. Street address of facility.

(24) *Point source*. A non-mobile source which emits 100 tons of NO_x or more per year unless the State designates as a point source a non-mobile source emitting at a specified level lower than 100 tons of NO_x per year. A non-mobile source which emits less NO_x per year than the point source threshold is an area source.

(25) *Pollutant code*. A unique code for each reported pollutant that has been assigned in the EIIP Data Model. Character names are used for criteria pollutants, while Chemical Abstracts Service (CAS) numbers are used for all other pollutants. Some States may be using storage and retrieval of aerometric data (SAROAD) codes for pollutants, but these should be able to be mapped to the EIIP Data Model pollutant codes.

(26) *Process rate/throughput*. A measurable factor or parameter that is directly or indirectly related to the emissions of an air pollution source. Depending on the type of source category, activity information may refer to the amount of fuel combusted, the amount of a raw material processed, the amount of a product that is manufactured, the amount of a material that is handled or processed, population, employment, number of units, or miles traveled. Activity information is typically the value that is multiplied against an emission factor to generate an emissions estimate.

(27) *SCC. Source category code*. A process-level code that describes the equipment or operation emitting pollutants.

(28) *Secondary control efficiency (%)*. The emissions reductions efficiency of a secondary control device, which shows the amount of reductions of a particular pollutant from a process' emissions due to controls or material change. Control

efficiency is usually expressed as a percentage or in tenths.

(29) *SIC. Standard Industrial Classification code*. U.S. Department of Commerce's categorization of businesses by their products or services.

(30) *Site name*. The name of the facility.

(31) *Spring throughput (%)*. Portion of throughput or activity for the 3 spring months (March, April, May). See the definition of Fall Throughput.

(32) *Stack diameter*. Stack physical diameter.

(33) *Stack height*. Stack physical height above the surrounding terrain.

(34) *Start date (inventory year)*. The calendar year that the emissions estimates were calculated for and are applicable to.

(35) *Start time (hour)*. Start time (if available) that was applicable and used for calculations of emissions estimates.

(36) *Summer throughput (%)*. Portion of throughput or activity for the 3 summer months (June, July, August). See the definition of Fall Throughput.

(37) *Summer work weekday emissions*. Average day's emissions for a typical day.

(38) *VMT by Roadway Class*. This is an expression of vehicle activity that is used with emission factors. The emission factors are usually expressed in terms of grams per mile of travel. Since VMT does not directly correlate to emissions that occur while the vehicle is not moving, these non-moving emissions are incorporated into EPA's MOBILE model emission factors.

(39) *Week/year in operation*. Weeks per year that the emitting process operates.

(40) *Work Weekday*. Any day of the week except Saturday or Sunday.

(41) *X coordinate (latitude)*. East-west geographic coordinate of an object.

(42) *Y coordinate (longitude)*. North-south geographic coordinate of an object.

PART 72—PERMITS REGULATION

1. The authority for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

2. Section 72.2 is amended by revising the definition for "excepted monitoring system," and adding new definitions in alphabetical order for "low mass emissions unit", "maximum potential hourly heat input", "maximum rated hourly heat input," and "ozone season" to read as follows:

§ 72.2 Definitions.

* * * * *

Excepted monitoring system means a monitoring system that follows the

procedures and requirements of § 75.19 of this chapter or of appendix D or E to part 75 for approved exceptions to the use of continuous emission monitoring systems.

* * * * *

Low mass emissions unit means an affected unit that is a gas-fired or oil-fired unit, burns only natural gas or fuel oil and qualifies under § 75.19 of this chapter.

* * * * *

Maximum potential hourly heat input means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use appendix D of part 75 of this chapter to report heat input, this value should be calculated, in accordance with part 75 of this chapter, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value should be reported, in accordance with part 75 of this chapter, using the maximum potential flow rate and either the maximum carbon dioxide concentration (in percent CO₂) or the minimum oxygen concentration (in percent O₂).

* * * * *

Maximum rated hourly heat input means a unit-specific maximum hourly heat input (mmBtu) which is the higher of the manufacturer's maximum rated hourly heat input or the highest observed hourly heat input.

* * * * *

Ozone season means the period of time beginning May 1 of a year and ending on September 30 of the same year, inclusive.

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

3. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651k, 7651 and note.

4. Section 75.1 is amended by revising paragraph (a) to read as follows:

§ 75.1 Purpose and scope.

(a) *Purpose*. The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and carbon dioxide (CO₂) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 of the CAA, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 (November 15, 1990). In addition, this part sets forth

provisions for the monitoring, recordkeeping, and reporting of NO_x mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a NO_x mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.

5. Section 75.2 is amended by revising paragraph (a) and adding a new paragraph (c) to read as follows:

§ 75.2 Applicability.

(a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO₂ or NO_x.

(c) The provisions of this part apply to sources subject to a State or federal NO_x mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.

6. Section 75.4 is amended by revising paragraph (a) introductory text to read as follows:

§ 75.4 Compliance dates.

(a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the Acid Rain permit which governs that unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the Acid Rain permit. For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the provisions of this part become applicable upon the submission of an opt-in permit application in accordance with § 74.14 of this chapter. The provisions of this part for the monitoring, recording, and reporting of NO_x mass emissions become applicable on the deadlines specified in the applicable State or federal NO_x mass emission reduction program, to the extent these provisions are adopted as requirements under such a program. In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all monitoring systems required by this part for monitoring SO₂, NO_x, CO₂, opacity, and volumetric flow are installed and that all certification tests are completed no later than the following dates (except as provided in

paragraphs (d) through (h) of this section):

7. Section 75.6 is amended by adding paragraph (f) to read as follows:

§ 75.6 Incorporation by reference.

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005-4070.

(1) American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; for § 75.19.

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992), for § 75.19.

8. Section 75.11 is amended by removing the period at the end of paragraph (d)(2) and replacing it with “; or” and adding paragraph (d)(3), to read as follows:

§ 75.11 Specific provisions for monitoring SO₂ emissions (SO₂ and flow monitors).

(d) By using the low mass emissions excepted methodology in § 75.19(c) for estimating hourly SO₂ mass emissions if the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b).

9. Section 75.12 is amended by revising the section heading, by redesignating paragraph (d) as paragraph (e), and by adding new paragraph (d) to read as follows:

§ 75.12 Specific provisions for monitoring NO_x emission rate (NO_x and diluent gas monitors).

(d) *Low mass emissions units.*

Notwithstanding the requirements of paragraphs (a) and (c) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a NO_x continuous emission monitoring system;

(2) Meet the requirements specified in paragraph (d)(2) of this section for using the excepted monitoring procedures in appendix E to this part, if applicable; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly NO_x emission rate and hourly NO_x mass emissions, if applicable under § 75.19(a) and (b).

10. Section 75.13 is amended by adding paragraph (d) to read as follows:

§ 75.13 Specific provisions for monitoring CO₂ emissions.

(d) *Determination of CO₂ mass emissions from low mass emissions units.* The owner or operator of a unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a CO₂ continuous emission monitoring system and flow monitoring system;

(2) Meet the requirements specified in paragraph (b) or (c) of this section for use of the methods in appendix G or F to this part, respectively; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly CO₂ mass emissions, if applicable under § 75.19(a) and (b).

11. Section 75.17 is amended by adding introductory text before paragraph (a) to read as follows:

§ 75.17 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for NO_x emission rate.

Notwithstanding the provisions of paragraphs (a), (b), and (c) of this section, the owner or operator of an affected unit that is using the procedures in this part to meet the monitoring and reporting requirements of a State or federal NO_x mass emission reduction program must also meet the provisions for monitoring NO_x emission rate in §§ 75.71 and 75.72.

12. Section 75.19 is added to subpart B to read as follows:

§ 75.19 Optional SO₂, NO_x, and CO₂ emissions calculation for low mass emissions units.

(a) *Applicability.* (1) Consistent with the requirements of paragraphs (a)(2) and (b) of this section, the low mass emissions excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of excepted methods under appendix D or E to this part, for the purpose of determining hourly heat input and hourly NO_x, SO₂, and CO₂ mass emissions from a low mass emissions unit.

(i) A low mass emissions unit is an affected unit that is gas-fired, or oil-fired unit, that burns only natural gas or fuel oil and for which:

(A) An initial demonstration is provided, in accordance with paragraph (a)(2) of this section, which shows that the unit emits no more than 25 tons of SO₂ annually and no more than 50 tons of NO_x annually; and

(B) An annual demonstration is provided thereafter, using one of the allowable methodologies in paragraph (c) of this section, showing that the low mass emission unit continues to emit no more than 25 tons of SO₂ annually and no more than 50 tons of NO_x annually.

(ii) Any qualifying unit must start using the low mass emissions excepted methodology in the first hour in which the unit operates in a calendar year. Notwithstanding, the earliest date for which a unit that meets the eligibility requirements of this section may begin to use this methodology is January 1, 2000.

(2) A unit may initially qualify as a low mass emissions unit only under the following circumstances:

(i) If the designated representative submits a certification application to use the low mass emissions excepted methodology and the Administrator certifies the use of such methodology. The certification application must contain:

(A) Actual SO₂ and NO_x mass emissions data for each of the three calendar years prior to the calendar year in which the certification application is submitted demonstrating to the satisfaction of the Administrator that the unit emits less than 25 tons of SO₂ and less than 50 tons of NO_x annually; and

(B) Calculated SO₂ and NO_x mass emissions, for each of the three calendar years prior to the calendar year in which the certification application is submitted, demonstrating to the satisfaction of the Administrator that the unit emits less than 25 tons of SO₂ and less than 50 tons of NO_x annually. The calculated emissions for each year shall

be determined using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate SO₂, NO_x, and CO₂ emission rate from paragraph (c)(1)(i) of this section for SO₂, paragraph (c)(1)(ii) or (c)(1)(iv) of this section for NO_x and paragraph (c)(1)(iii) of this section for CO₂; or

(ii) When the three full years of actual, historical SO₂ and NO_x mass emissions data required under paragraph (a)(2)(i) of this section are not available, the designated representative may submit an application to use the low mass emissions excepted methodology based upon a combination of historical SO₂ and NO_x mass emissions data and projected SO₂ and NO_x mass emissions, totaling three years. Historical data must be used for any years in which historical data exists and projected data should be used for any remaining future years needed to provide capacity factor data for three consecutive calendar years. For example, if a unit commenced operation two years ago, the designated representative may submit actual, historical data for the previous two years and one year of projected emissions for the current calendar year or, for unit that commenced operation after January 1, 1997, the designated representative may submit three years of projected emissions, beginning with the current calendar year. Any actual or projected annual emissions must demonstrate to the satisfaction of the Administrator that the unit will emit less than 25 tons of SO₂ and less than 50 tons of NO_x annually. Projected emissions shall be calculated using either the default emission rates in tables 1, 2 and 3 of this section, or for NO_x emission rate a fuel-and-unit-specific NO_x emission rate determined in accordance with the testing procedures in paragraph (c)(1)(iv) of this section, in conjunction with projections of unit operating hours or fuel type and fuel usage, according to one of the allowable calculation methodologies in paragraph (c) of this section.

(b) *On-going qualification and disqualification.* (1) Once a low mass emission unit has qualified for and has started using the low mass emissions excepted methodology, an annual demonstration is required, showing that the unit continues to emit less than 25 tons of SO₂ annually and less than 50 tons of NO_x annually. The calculation methodology used for the annual demonstration shall be the same methodology, from paragraph (c) of this

section, by which the unit initially qualified to use the low mass emissions excepted methodology.

(2) If any low mass emission unit fails to provide the required annual demonstration under paragraph (b)(1) of this section, such that the calculated cumulative year-to-date emissions for the unit exceed 25 tons of SO₂ or 50 tons of NO_x in any calendar quarter of any calendar year, then;

(i) The low mass emission unit shall be disqualified from using the low mass emissions excepted methodology as of the end of the second calendar quarter following such quarter in which either the 25 ton limit for SO₂ or the 50 ton limit for NO_x was exceeded; and

(ii) The owner or operator of the low mass emission unit shall have two calendar quarters from the end of the quarter in which the unit exceeded the 25 ton limit for SO₂ or the 50 ton limit for NO_x to install, certify, and report SO₂, NO_x, and CO₂ emissions from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13.

(3) If a low mass emission unit that initially qualifies to use the low mass emissions excepted methodology under this section changes fuels, such that a fuel other than those allowed for use in the low mass emissions methodology (e.g. natural gas or fuel oil) is combusted in the unit, the unit shall be disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. The owner or operator shall install, certify, and report SO₂, NO_x, and CO₂ from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13 prior to a change to such fuel. The owner or operator must notify the Administrator in the case where a unit switches fuels without previously having installed and certified a SO₂, NO_x and CO₂ monitoring system meeting the requirements of §§ 75.11, 75.12, and 75.13.

(4) If a unit commencing operation after January 1, 1997 initially qualifies to use the low mass emissions excepted methodology under this section and the owner or operator wants to use a low mass emissions methodology for the unit, he or she must:

(i) Keep the records specified in paragraph (c)(2) of this section, beginning with the date and hour of commencement of commercial operation, for a unit subject to an Acid Rain emission limitation, and beginning with the date and hour of the commencement of operation, for a unit subject to a NO_x mass reduction program;

(ii) Use these records to determine the cumulative heat input and SO₂, NO_x, and CO₂ mass emissions in order to continue to qualify as a low mass emission unit; and

(iii) Determine the cumulative SO₂ and NO_x mass emissions according to paragraph (c) of this section using the same procedures used after the certification deadline for the unit, for purposes of demonstrating eligibility to use the excepted methodology set forth in this section. For example, use the default emission rates in tables 1, 2 and 3 of this section or use the fuel-and-unit-specific NO_x emission rate determined according to paragraph (c)(1)(iv) of this section. The Administrator will not count SO₂ mass emissions calculated for the period between commencement of commercial operation and the certification deadline for the unit under § 75.4 against SO₂ allowances to be held in the unit account.

(5) A low mass emission unit that has been disqualified from using the low mass emissions excepted methodology may subsequently qualify again to use the low mass emissions methodology under paragraph (a)(2) of this section, provided that if such unit qualified under paragraph (a)(2)(ii) of this section, the unit may subsequently qualify again only if the unit meets the requirements of paragraph (a)(2)(i) of this section.

(c) *Low mass emissions excepted methodology, calculations, and values.*

(1) *Determination of SO₂, NO_x, and CO₂ emission rates.*

(i) Use Table 1 of this section to determine the appropriate SO₂ emission rate for use in calculating hourly SO₂ mass emissions under this section.

(ii) Use either the appropriate NO_x emission factor from Table 2 of this section, or a fuel-and-unit-specific NO_x emission rate determined according to paragraph (c)(1)(iv) of this section, to calculate hourly NO_x mass emissions under this section.

(iii) Use Table 3 of this section to determine the appropriate CO₂ emission rate for use in calculating hourly CO₂ mass emissions under this section.

(iv) In lieu of using the default NO_x emission rate from Table 2 of this section, the owner or operator may, for each fuel combusted by a low mass emission unit, determine a fuel-and-unit-specific NO_x emission rate for the purpose of calculating NO_x mass emissions under this section. This option may be used by any unit which qualifies to use the low mass emission excepted methodology under paragraph (a) of this section, and also by groups of units which combust fuel from a common source of supply and which

use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine heat input. If this option is chosen, the following procedures shall be used.

(A) Except as otherwise provided in paragraphs (c)(1)(iv)(F) and (G) of this paragraph, determine a fuel-and-unit-specific NO_x emission rate by conducting a four load NO_x emission rate test procedure as specified in section 2.1 of appendix E to this part, for each type of fuel combusted in the unit. For a group of units sharing a common fuel supply, the appendix E testing must be performed on each individual unit in the group, unless some or all of the units in the group belong to an identical group of units, as defined in paragraph (c)(1)(iv)(B) of this section, in which case, representative testing may be conducted on units in the identical group of units, as described in paragraph (c)(1)(iv)(B) of this section. For the purposes of this section, make the following modifications to the appendix E test procedures:

(1) Do not measure the heat input as required under 2.1.3 of appendix E to this part.

(2) Do not plot the test results as specified under 2.1.6 of appendix E to this part.

(B) Representative appendix E testing may be done on low mass emission units in a group of identical units. All of the units in a group of identical units must combust the same fuel type but do not have to share a common fuel supply.

(1) To be considered identical, all low mass emission units must be of the same size (based on maximum rated hourly heat input), manufacturer and model, and must have the same history of modifications (e.g., have the same controls installed, the same types of burners and have undergone major overhauls at the same frequency (based on hours of operation)). Also, under similar operating conditions, the stack or turbine outlet temperature of each unit must be within ± 50 degrees Fahrenheit of the average stack or turbine outlet temperature for all of the units.

(2) If all of the low mass emission units in the group qualify as identical, then representative testing of the units in the group may be performed according to Table 4 of this section.

(3) If there are only two low mass emission units in the group of identical units, the results of the representative testing under paragraph (c)(1)(iv)(B)(1) of this section may be used to establish the fuel-and-unit-specific NO_x emission rate(s) for the units. However, if there are more than two low mass emission

units in the group, the testing must confirm that the units are identical by meeting the following criteria. The results of the representative testing may only be used to establish the fuel-and-unit-specific NO_x emission rate(s) for such units if the following criteria are met:

(i) at each of the four load levels tested, the NO_x emission rate for each tested low mass emission unit does not differ by more than $\pm 10\%$ from the average of the NO_x emission rates for all units tested, or;

(ii) if the average NO_x emission rate of all low mass emission units tested at all four load levels is less than 0.20 lb/mmBtu, an alternative criteria of ± 0.020 lb/mmBtu may be used in lieu of the 10% criteria. Units must all be within ± 0.020 lb/mmBtu of the average from the test to be considered identical units under this section.

(4) If the acceptance criteria in paragraph (c)(1)(iv)(B)(3) of this section are not met then the group of low mass emission units is not considered an identical group of units and individual appendix E testing of each unit is required.

(5) Fuel and unit specific NO_x emission rates determined according to paragraphs (c)(1)(iv)(F) and (c)(1)(iv)(G) of this section may be used in lieu of appendix E testing for one or more low mass emission units in a group of identical units.

(C) Based on the results of the appendix E testing, determine the fuel-and-unit-specific NO_x emission rate as follows:

(1) For an individual low mass emission unit with no NO_x emissions controls of any kind, the highest NO_x emission rate obtained for a particular type of fuel in the appendix E test multiplied by 1.15 shall be the fuel-and-unit-specific NO_x emission rate, for that type of fuel.

(2) For a group of low mass emission units sharing a common fuel supply with no NO_x controls of any kind on any of the units, the highest NO_x emission rate obtained for a particular type of fuel in all of the appendix E tests of all units in the group of units sharing a common fuel supply multiplied by 1.15 shall be the fuel-and-unit-specific NO_x emission rate for each unit in the group, for that type of fuel.

(3) For a group of identical low mass emission units which perform representative testing according to paragraph (c)(1)(iv)(B) of this section with no NO_x controls of any kind on any of the units, the fuel-and-unit-specific NO_x emission rate for all units, for a particular type of fuel, multiplied by 1.15 shall be the highest NO_x

emission rate from any unit tested in the group, for that type of fuel.

(4) For an individual low mass emission unit which has NO_x emission controls of any kind, the fuel-and-unit-specific NO_x emission rate for each type of fuel combusted in the unit shall be the higher of:

(i) The highest emission rate from the appendix E test for that type of fuel multiplied by 1.15; or

(ii) 0.15 lb/mmBtu.

(5) For a group of low mass emission units sharing a common fuel supply, one or more of which has NO_x controls of any kind, the fuel-and-unit-specific NO_x emission rate for each unit in the group of units sharing a common fuel supply shall, for a particular type of fuel combusted by the group of units sharing a common fuel supply, shall be the higher of:

(i) The highest NO_x emission rate from all appendix E tests of all low mass emission units in the group for that type of fuel multiplied by 1.15; or

(ii) 0.15 lb/mmBtu.

(6) For a group of identical low mass emission units, which perform representative testing according to paragraph (c)(1)(iv)(B) of this section and have identical NO_x controls, the fuel-and-unit-specific NO_x emission rate for each unit in the group of units, for a particular type of fuel, shall be the higher of:

(i) The highest NO_x emission rate from all appendix E tests of all tested low mass emission units in the group of identical units for that type of fuel multiplied by 1.15; or

(ii) 0.15 lb/mmBtu.

(D) For each low mass emission unit, each unit in a group of units sharing a common fuel supply, or identical units for which the provisions of paragraph (c)(1)(iv) of this section are used to account for NO_x emission rate, the owner or operator shall determine a new fuel-and-unit-specific NO_x emission rate every five years, unless changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation, or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_x emission rate. If such changes occur, the fuel-and-unit-specific NO_x emission rate(s) shall be re-determined according to paragraph (c)(1)(iv) of this section. If a low mass emission unit belongs to a group of identical units and it is required to retest to determine a new fuel-and-unit-specific NO_x emission rate because of changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a

significant increase in the unit's actual NO_x emission rate, any other unit in that group of identical units is not required to re-determine the fuel-and-unit-specific NO_x emission rate unless such unit also undergoes changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_x emission rates.

(E) Each low mass emission unit, each low mass emission unit in a group of units combusting a common fuel, or each low mass emission unit in a group of identical units for which a fuel-and-unit-specific NO_x emission rate(s) are determined shall meet the quality assurance and quality control provisions of paragraph (e) of this section.

(F) Low mass emission units may use the results of appendix E testing, if such test results are available from a test conducted no more than five years prior to the time of initial certification, to determine the appropriate fuel-and-unit-specific NO_x emission rate(s). However, fuel-and-unit-specific NO_x emission rates from historical testing may not be used longer than five years after the appendix E testing was conducted.

(G) Low mass emission units for which at least 3 years of NO_x emission rate continuous emissions monitoring system data and corresponding fuel usage data are available may determine fuel-and-unit-specific NO_x emission rates from the actual data using the following procedure. Separate the actual NO_x emission rate data into groups, according to the type of fuel combusted. Discard data from periods when multiple fuels were combusted. Each fuel-specific data set must contain at least 168 hours of data and must represent all normal operating ranges of the unit when combusting the fuel. Sort the data in each fuel-specific data set in ascending order according to NO_x emission rate. Determine the 95th percentile NO_x emission rate for each data set as defined in § 72.2 of this chapter. Use the 95th percentile value for each data set as the fuel-and-unit-specific NO_x emission rate, except that for a unit with NO_x emission controls of any kind, if the 95th percentile value is less than 0.15 lb/mmBtu, a value of 0.15 lb/mmBtu shall be used as the fuel-and-unit-specific NO_x emission rate.

(H) For low mass emission units with NO_x emission controls, the owner or operator shall, during every hour of unit operation during the test period, monitor and record parameters, as required under paragraph (e)(5) of this section, which indicate that the NO_x emission controls are operating

properly. After the test period, these same parameters shall be monitored and recorded and kept for all operating hours in order to determine whether the NO_x controls are operating properly and to allow the determination of the correct NO_x emission rate as required under paragraph (c)(1)(iv) of this section.

(I) For low mass emission units with steam or water injection, the steam-to-fuel or water-to-fuel ratio used during the testing must be documented. The water-to-fuel or steam-to-fuel ratio must be maintained during unit operations for a unit to use the fuel and unit specific NO_x emission rate determined during the test. Owners or operators must include in the monitoring plan the acceptable range of the water-to-fuel or steam-to-fuel ratio, which will be used to indicate hourly, proper operation of the NO_x controls for each unit. The water-to-fuel or steam-to-fuel ratio shall be monitored and recorded during each hour of unit operation. If the water-to-fuel or steam-to-fuel ratio is not within the acceptable range in a given hour the fuel and unit specific NO_x emission rate may not be used for that hour.

(2) For low mass emission units with other types of NO_x controls, appropriate parameters and the acceptable range of the parameters which indicate hourly proper operation of the NO_x controls must be specified in the monitoring plan. These parameters shall be monitored during each subsequent operating hour. If any of these parameters are not within the acceptable range in a given operating hour, the fuel and unit specific NO_x emission rates may not be used in that hour.

(2) *Records of operating time, fuel usage, unit output and NO_x emission control operating status.* The owner or operator shall keep the following records on-site, for three years, in a form suitable for inspection:

(i) For each low mass emission unit, the owner or operator shall keep hourly records which indicate whether or not the unit operated during each clock hour of each calendar year. The owner or operator may report partial operating hours or may assume that for each hour the unit operated the operating time is a whole hour. Units using partial operating hours and the maximum rated hourly heat input to calculate heat input for each hour must report partial operating hours.

(ii) For each low mass emissions unit, the owner or operator shall keep hourly records indicating the type(s) of fuel(s) combusted in the unit during each hour of unit operation.

(iii) For each low mass emission unit using the long term fuel flow methodology under paragraph (c)(3)(ii)

of this section to determine hourly heat input, the owner or operator shall keep hourly records of unit output (in megawatts or thousands of pounds of steam), for the purpose of apportioning heat input to the individual unit operating hours.

(iv) For each low mass emission unit with NO_x emission controls of any kind, the owner or operator shall keep hourly records of the hourly value of the parameter(s) specified in (c)(1)(iv)(H) of this section used to indicate proper operation of the unit's NO_x controls.

(3) *Heat input.* Hourly, quarterly and annual heat input for a low mass emission unit shall be determined using either the maximum rated hourly heat input method under paragraph (c)(3)(i) of this section or the long term fuel flow method under paragraph (c)(3)(ii) of this section.

(i) *Maximum rated hourly heat input method.* (A) For the purposes of the mass emission calculation methodology of paragraph (c)(3) of this section, the hourly heat input (mmBtu) to a low mass emission unit shall be deemed to equal the maximum rated hourly heat input, as defined in § 72.2 of this chapter, multiplied by the operating time of the unit for each hour. The owner or operator may choose to record and report partial operating hours or may assume that a unit operated for a whole hour for each hour the unit operated. However, the owner or operator of a unit may petition the Administrator under § 75.66 for a lower value for maximum rated hourly heat input than that defined in § 72.2 of this chapter. The Administrator may approve such lower value if the owner or operator demonstrates that either the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and such a lower value is representative, of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(B) The quarterly heat input, HI_{qtr} , in mmBtu, shall be determined using Equation LM-1:

$$HI_{qtr} = T_{qtr} \times HI_{hr} \quad (\text{Eq. LM-1})$$

Where:

T_{qtr} = Actual number of operating hours in the quarter (hr).

HI_{hr} = Hourly heat input under paragraph (c)(3)(i)(A) of this section (mmBtu).

(C) The year-to-date cumulative heat input (mmBtu) shall be the sum of the quarterly heat input values for all of the calendar quarters in the year to date.

(ii) *Long term fuel flow heat input method.* The owner or operator may, for

the purpose of demonstrating that a low mass emission unit or group of low mass emission units sharing a common fuel supply meets the requirements of this section, use records of long-term fuel flow, to calculate hourly heat input to a low mass emission unit.

(A) This option may be used for a group of low mass emission units only if:

(1) The low mass emission units combust fuel from a common source of supply; and

(2) Records are kept of the total amount of fuel combusted by the group of low mass emission units and the hourly output (in megawatts or pounds of steam) from each unit in the group; and

(3) All of the units in the group are low mass emission units.

(B) For each fuel used during the quarter, the volume in standard cubic feet (for gas) or gallons (for oil) may be determined using any of the following methods:

(1) Fuel billing records (for low mass emission units, or groups of low mass emission units, which purchase fuel from non-affiliated sources);

(2) American Petroleum Institute (API) standard, American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (incorporated by reference under § 75.6); or;

(3) A fuel flow meter certified and maintained according to appendix D to this part.

(C) For each fuel combusted during a quarter, the gross calorific value of the fuel shall be determined by either:

(1) Using the applicable procedures for gas and oil analysis in sections 2.2

and 2.3 of appendix D to this part. If this option is chosen the highest gross calorific value recorded during the previous calendar year shall be used; or

(2) Using the appropriate default gross calorific value listed in Table 5 of this section.

(D) For each type of fuel oil combusted during the quarter, the specific gravity of the oil shall be determined either by:

(1) Using the procedures in section 2.2.6 of appendix D to this part. If this option is chosen, use the highest specific gravity value recorded during the previous calendar year shall be used; or

(2) Using the appropriate default specific gravity value in Table 5 of this section.

(E) The quarterly heat input from each type of fuel combusted during the quarter by a low mass emission unit or group of low mass emission units sharing a common fuel supply shall be determined using Equation LM-2 for oil and LM-3 for natural gas.

$$HI_{\text{fuel-qtr}} = M_{\text{qtr}} \frac{GCV_{\text{max}}}{10^6}$$

Eq LM-2 (for fuel oil or diesel fuel)

Where:

$HI_{\text{fuel-qtr}}$ = Quarterly total heat input from oil (mmBtu).

M_{qtr} = Mass of oil consumed during the entire quarter, determined as the product of the volume of oil under paragraph (c)(3)(ii)(B) of this section and the specific gravity under paragraph (c)(3)(ii)(D) of this section (lb)

GCV_{max} = Gross calorific value of oil, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/lb)

10^6 = Conversion of Btu to mmBtu.

$$HI_{\text{fuel-qtr}} = Q_g \frac{GCV_{\text{max}}}{10^6}$$

Eq LM-3 (for natural gas)

Where:

$HI_{\text{fuel-qtr}}$ = Quarterly heat input from natural gas (mmBtu).

Q_g = Value of natural gas combusted during the quarter, as determined under paragraph (c)(3)(ii)(B) of this section standard cubic feet (scf).

GCV_g = Gross calorific value of the natural gas combusted during the quarter, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/scf)

10^6 = Conversion of Btu to mmBtu.

(F) The quarterly heat input (mmBtu) for all fuels for the quarter, $HI_{\text{qtr-total}}$, shall be the sum of the $HI_{\text{fuel-qtr}}$ values determined using Equations LM-2 and LM-3.

$$HI_{qtr-total} = \sum_{all-fuels} HI_{fuel-qtr}$$

(Eq. LM-4)

(G) The year-to-date cumulative heat input (mmBtu) for all fuels shall be the sum of all quarterly total heat input ($HI_{qtr-total}$) values for all calendar quarters in the year to date.

(H) For each low mass emission unit, each low mass emission unit of an identical group of units, or each low mass emission unit in a group of units sharing a common fuel supply, the owner or operator shall determine the quarterly unit output in megawatts or pounds of steam. The quarterly unit output shall be the sum of the hourly unit output values recorded under paragraph (c)(2) of this section and shall be determined using Equations LM-5 or LM-6.

$$MW_{qtr} = \sum_{all-hours} MW$$

Eq LM-5 (for MW output)

$$ST_{qtr} = \sum_{all-hours} ST$$

Eq LM-6 (for steam output)

Where:

MW_{qtr} = the power produced during all hours of operation during the quarter by the unit (MW)

$ST_{fuel-qtr}$ = the total quarterly steam output produced during all hours of operation during the quarter by the unit (klb)

MW = the power produced during each hour in which the unit operated during the quarter (MW).

ST = the steam output produced during each hour in which the unit operated during the quarter (klb)

(I) For a low mass emission unit that is not included in a group of low mass emission units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr-total}$ to each hour of unit operation using either Equation LM-7 or LM-8:

$$HI_{hr} = HI_{qtr-total} \frac{MW_{hr}}{MW_{qtr}}$$

(Eq LM-7 for MW output)

$$HI_{hr} = HI_{qtr-total} \frac{ST_{hr}}{ST_{qtr}}$$

(Eq LM-8 for steam output)

Where:

HI_{hr} = hourly heat input to the unit (mmBtu)

MW_{hr} = hourly output from the unit (MW)

ST_{hr} = hourly steam output from the unit (klb)

(J) For each low mass emission unit that is included in a group of units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr-total}$ to each hour of operation using either Equation LM-7a or LM-8a:

$$HI_{hr} = HI_{qtr-total} \frac{MW_{hr}}{\sum_{all-units} MW_{qtr}}$$

(Eq LM-7a for MW output)

$$HI_{hr} = HI_{qtr-total} \frac{ST_{hr}}{\sum_{all-units} ST_{qtr}}$$

(Eq LM-8a for steam output)

Where:

HI_{hr} = hourly heat input to the individual unit (mmBtu)

MW_{hr} = hourly output from the individual unit (MW)

ST_{hr} = hourly steam output from the individual unit (klb)

$\sum_{all-units} MW_{qtr}$ = Sum of the quarterly outputs (from Eq. LM-5) for all units in the group (MW)

$\sum_{all-units} ST_{qtr}$ = Sum of the quarterly steam outputs (from Eq. LM-6) for all units in the group (klb)

(4) *Calculation of SO₂, NO_x and CO₂ mass emissions.* The owner or operator shall, for the purpose of demonstrating that a low mass emission unit meets the requirements of this section, calculate SO₂, NO_x and CO₂ mass emissions in accordance with the following.

(i) *SO₂ mass emissions.* (A) The hourly SO₂ mass emissions (lbs) for a low mass emission unit shall be determined using Equation LM-9 and the appropriate fuel-based SO₂ emission factor from Table 1 of this section for the fuels combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$$W_{SO_2} = EF_{SO_2} \times HI_{hr} \quad (\text{Eq. LM-9})$$

where:

W_{SO_2} = Hourly SO₂ mass emissions (lbs).
 EF_{SO_2} = SO₂ emission factor from Table 1 of this section (lb/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input under paragraph (c)(3)(i)(A) of this section or the hourly heat input under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly SO₂ mass emissions (tons) for the low mass emission unit shall be the sum of all the hourly SO₂ mass emissions in the quarter, as determined under paragraph (c)(4)(i)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative SO₂ mass emissions (tons) for the low mass emission unit shall be the sum of the quarterly SO₂ mass emissions, as determined under paragraph (c)(4)(i)(B) of this section, for all of the calendar quarters in the year to date.

(ii) *NO_x mass emissions.* (A) The hourly NO_x mass emissions for the low mass emission unit (lbs) shall be determined using Equation LM-10. If more than one fuel is combusted in the hour, use the highest emission rate for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit. For low mass emission units with NO_x emission controls of any kind and for which a fuel-and-unit-specific NO_x emission rate is determined under paragraph (c)(1)(iv) of this section, for any hour in which the parameters under paragraph (c)(1)(iv)(A) of this section do not show that the NO_x emission controls are operating properly, use the NO_x emission rate from Table 2 of this section for the fuel combusted during the hour with the highest NO_x emission rate.

$$W_{NO_x} = EF_{NO_x} \times HI_{hr} \quad (\text{Eq. LM-10})$$

Where:

W_{NO_x} = Hourly NO_x mass emissions (lbs).

EF_{NO_x} = Either the NO_x emission factor from Table 1b of paragraph (c)(1)(ii) of this section of this section or the fuel-and-unit-specific NO_x emission rate determined under paragraph (c)(1)(iv) of this section (lb/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly NO_x mass emissions (tons) for the low mass emission unit shall be the sum of all of the hourly NO_x mass emissions in the quarter, as determined under paragraph (c)(4)(ii)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative NO_x mass emissions (tons) for the low mass emission unit shall be the sum of the

quarterly NO_x mass emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for all of the calendar quarters in the year to date.

(iii) *CO₂ Mass Emissions.* (A) The hourly CO₂ mass emissions (tons) for the affected low mass emission unit shall be determined using Equation LM-11 and the appropriate fuel-based CO₂ emission factor from Table 3 of this section for the fuel being combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$$WCO_2 = EFCO_2 \times HI_{hr} \quad (\text{Eq. LM-11})$$

Where:

WCO₂ = Hourly CO mass emissions (tons).

EFCO₂ = Fuel-based CO₂ emission factor from Table 3 of this section (ton/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly CO₂ mass emissions (tons) for the low mass emission unit shall be the sum of all of the hourly CO₂ mass emissions in the quarter, as determined under paragraph (c)(4)(iii)(A) of this section.

(C) The year-to-date cumulative CO₂ mass emissions (tons) for the low mass emission unit shall be the sum of all of the quarterly CO₂ mass emissions, as determined under paragraph (c)(4)(iii)(B) of this section, for all of the calendar quarters in the year to date.

(d) Each unit that qualifies under this section to use the low mass emissions methodology must follow the recordkeeping and reporting requirements pertaining to low mass emissions units in subparts F and G of this part.

(e) The quality control and quality assurance requirements in § 75.21 are not applicable to a low mass emissions unit for which the low mass emissions excepted methodology under paragraph (c) of this section is being used in lieu of a continuous emission monitoring system or an excepted monitoring system under appendix D or E to this part, except for fuel flowmeters used to meet the provisions in paragraph (c)(3)(ii) of this section. However, the owner or operator of a low mass emissions unit shall implement the following quality assurance and quality control provisions:

(1) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use fuel billing records to determine fuel usage, the owner or operator shall keep, at the facility, for three years, the records of the fuel billing statements used for long term fuel flow determinations.

(2) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use American Petroleum Institute (API) standard, American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997, Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (incorporated by reference under § 75.6), to determine fuel usage, the owner or operator shall keep, at the facility, a copy of the standard used and shall keep records, for three years, of all measurements obtained for each quarter using the methodology.

(3) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use a certified fuel flow meter to determine fuel usage, the owner or operator shall comply with the quality control quality assurance requirements for a fuel flow meter under section 2.1.6 of appendix D of this part.

(4) For each low mass emission unit for which fuel-and-unit-specific NO_x emission rates are determined in accordance with paragraph (c)(1)(iv) of this section, the owner or operator shall keep, at the facility, records which document the results of all NO_x emission rate tests conducted according to appendix E to this part. If CEMS data

are used to determine the fuel-and-unit-specific NO_x emission rates under paragraph (c)(1)(iv)(G) of this section, the owner or operator shall keep, at the facility, records of the CEMS data and the data analysis performed to determine a fuel-and-unit-specific NO_x emission rate. The appendix E test records and historical CEMS data records shall be kept until the fuel and unit specific NO_x emission rates are re-determined.

(5) For each low mass emission unit for which fuel-and-unit-specific NO_x emission rates are determined in accordance with paragraph (c)(1)(iv) of this section and which have NO_x emission controls of any kind, the owner or operator shall develop and keep on-site a quality assurance plan which explains the procedures used to document proper operation of the NO_x emission controls. The plan shall include the parameters monitored (e.g., water-to-fuel ratio) and the acceptable ranges for each parameter used to determine proper operation of the unit's NO_x controls.

TABLE 1 OF § 75.19: SO₂ Emission Factors (lb/mmBtu) for Various Fuel Types

Fuel type	SO ₂ emission factors
Pipeline Natural Gas	0.0006 lb/mmBtu.
Other Natural Gas	0.06 lb/mmBtu.
Residual Oil	2.1 lb/mmBtu.
Diesel Fuel	0.5 lb/mmBtu.

TABLE 2 OF § 75.19: NO_x Emission Rates (lb/mmBtu) for Various Boiler/Fuel Types

Boiler type	Fuel type	NO _x emission rate
Turbine	Gas	0.7
Turbine	Oil	1.2
Boiler	Gas	1.5
Boiler	Oil	2

TABLE 3 OF § 75.19: CO₂ Emission Factors (ton/mmBtu) for Gas and Oil

Fuel type	CO ₂ emission factors
Natural Gas	0.059 ton/mmBtu.
Oil	0.081 ton/mmBtu.

TABLE 4 OF § 75.19: IDENTICAL UNIT TESTING REQUIREMENTS

Number of identical units in the group	Number of appendix E tests required
2	1
3 to 6	2

TABLE 4 OF § 75.19: IDENTICAL UNIT TESTING REQUIREMENTS—Continued

Number of identical units in the group	Number of appendix E tests required
7	3
> 7	n tests; where n = number of units divided by 3 and rounded to nearest integer.

TABLE 5 OF § 75.19: DEFAULT GROSS CALORIFIC VALUES (GCVs) FOR VARIOUS FUELS

Fuel	GCV for use in equation LM-2 or LM-3
Pipeline Natural Gas	1051 Btu/scf.
Natural Gas	1118 Btu/scf.
Residual Oil	19,708 Btu/gallon.
Diesel Fuel	20,500 Btu/gallon.

TABLE 6 OF § 75.19: DEFAULT SPECIFIC GRAVITY VALUES FOR FUEL OIL

Fuel	Specific gravity (lb/gal)
Residual Oil	8.5
Diesel Fuel	7.4

13. Section 75.20 is amended by adding new paragraph (h) to read as follows:

§ 75.20 Certification and recertification procedures.

* * * * *

(h) *Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19.* The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under § 75.19 shall meet the applicable general operating requirements of § 75.10, the applicable requirements of § 75.19, and the applicable certification requirements of this paragraph.

(1) *Monitoring plan.* The designated representative shall submit a monitoring plan in accordance with §§ 75.53 and 75.62. The designated representative for an owner or operator who wishes to use fuel-and unit-specific NO_x emission rate testing for units with NO_x controls under § 75.19(c)(1)(iv) must submit in the monitoring plan the parameters monitored which will be used to determine operation of the NO_x emission controls. For units using water or steam injection to control NO_x, the water-to-fuel or steam-to-fuel range of values must be documented.

(2) *Certification application.* [reserved]

(3) *Approval of certification applications.* The provisions for the certification application formal approval process in the introductory text of paragraph (a)(4) and in paragraphs (a)(4)(i), (ii), and (iv) of this section shall apply, except that "continuous emission or opacity monitoring system" shall be replaced with "excepted methodology." The excepted methodology shall be deemed provisionally certified for use under the Acid Rain Program, as of the following dates:

(i) For a unit that commenced operation on or before January 1, 1997, from January 1 of the year following submission of the certification application until the completion of the period for the Administrator's review; or

(ii) For a unit that commenced operation after January 1, 1997, from the date of submission of a certification application for approval to use the low mass emissions excepted methodology under § 75.19 until the completion of the period for the Administrator's review, except that the methodology may be used retrospectively until the date and hour that the unit commenced operation for purposes of demonstrating that the unit qualified to use the methodology under § 75.19(b)(4)(iii).

(4) *Disapproval of certification applications.* If the Administrator determines that the certification application does not demonstrate that the unit meets the requirements of §§ 75.19(a) and (b), the Administrator shall issue a written notice of disapproval of the certification application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification is invalidated by the Administrator, and the data recorded under the excepted methodology shall not be considered valid. The owner or operator shall follow the procedures for loss of certification:

(i) The owner or operator shall substitute the following values, as applicable, for each hour of unit operation during the period of invalid data specified in paragraph (a)(4)(iii) of this section or in §§ 75.21(e) (introductory paragraph) and 75.21(e)(1): the maximum potential concentration of SO₂, as defined in section 2.1.1.1 of appendix A to this part to report SO₂ concentration; the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter to report NO_x emission rate; the maximum potential flow rate, as defined in section 2.1 of appendix A to this part to report volumetric flow; or the maximum CO₂ concentration used to determine the

maximum potential concentration of SO₂ in section 2.1.1.1 of appendix A to this part to report CO₂ concentration data. For a unit subject to a State or federal NO_x mass reduction program where the owner or operator intends to monitor NO_x mass emissions with a NO_x pollutant concentration monitor and a flow monitoring system, substitute for NO_x concentration using the maximum potential concentration of NO_x, as defined in section 2.1.2.1 of appendix A to this part, and substitute for volumetric flow using the maximum potential flow rate, as defined in section 2.1 of appendix A to this part. The owner or operator shall substitute these values until such time, date, and hour as a continuous emission monitoring system or excepted monitoring system, where applicable, is installed and provisionally certified;

(ii) The designated representative shall submit a notification of certification test dates, as specified in § 75.61(a)(1)(ii), and a new certification application according to the procedures in paragraph (a)(2) of this section; and

(iii) The owner or operator shall install and provisionally certify continuous emission monitoring systems or excepted monitoring systems, where applicable, two calendar quarters from the end of the quarter in which the unit no longer qualifies as a low mass emissions unit.

14. Section 75.24 is amended by revising paragraph (d) to read as follows:

§ 75.24 Out-of-control periods.

* * * * *

(d) When the bias test indicates that an SO₂ monitor, a volumetric flow monitor, a NO_x continuous emission monitoring system or a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2), is biased low (i.e., the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test, or calculate and use the bias adjustment factor as specified in section 2.3.3 of appendix B to this part and in accordance with § 75.7.

* * * * *

16. Subpart H is added to part 75 to read as follows:

Subpart H—NO_x Mass Emissions Provisions

Sec.

- 75.70 NO_x mass emissions provisions.
- 75.71 Specific provisions for monitoring NO_x emission rate and heat input for the purpose of calculating NO_x mass emissions.
- 75.72 Determination of NO_x mass emissions.
- 75.73 Recordkeeping and reporting [Reserved].
- 75.74 Annual and ozone season monitoring and reporting requirements.
- 75.75 Additional ozone season calculation procedures for special circumstances.

Subpart H—NO_x Mass Emissions Provisions**§ 75.70 NO_x mass emissions provisions.**

(a) *Applicability.* The owner or operator of a unit shall comply with the requirements of this subpart to the extent that compliance is required by an applicable State or federal NO_x mass emission reduction program that incorporates by reference, or otherwise adopts the provisions of, this subpart.

(1) For purposes of this subpart, the term "affected unit" shall mean any unit that is subject to a State or federal NO_x mass emission reduction program requiring compliance with this subpart, the term "nonaffected unit" shall mean any unit that is not subject to such a program, the term "permitting authority" shall mean the permitting authority under an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart, and the term "designated representative" shall mean the responsible party under the applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.

(2) In addition, the provisions of subparts A, C, D, E, F, and G and appendices A through G of this part applicable to NO_x concentration, flow rate, NO_x emission rate and heat input, as set forth and referenced in this subpart, shall apply to the owner or operator of a unit required to meet the requirements of this subpart by a State or federal NO_x mass emission reduction program. When applying these requirements, the term "affected unit" shall mean any unit that is subject to a State or federal NO_x mass emission reduction program requiring compliance with this subpart, the term "permitting authority" shall mean the permitting authority under an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart, and the term "designated representative" shall mean the responsible party under the applicable

State or federal NO_x mass emission reduction program that adopts the requirements of this subpart. The requirements of this part for SO₂, CO₂ and opacity monitoring, recordkeeping and reporting do not apply to units that are subject to a State or federal NO_x mass emission reduction program only and are not affected units with an Acid Rain emission limitation.

(b) *Compliance dates.* The owner or operator of an affected unit shall meet the compliance deadlines established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.

(c) *Prohibitions.* (1) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with paragraph (h) of this section.

(2) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged emissions of NO_x to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this part, except as provided in § 75.74.

(3) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_x mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of this part applicable to monitoring systems under § 75.71, except as provided in § 75.74.

(4) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this part, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption that is in effect under the State or federal NO_x mass emission reduction program that adopts the requirements of this subpart;

(ii) The owner or operator is monitoring NO_x mass emissions from the affected unit with another certified

monitoring system approved, in accordance with the provisions of paragraph (d) of this section; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 75.61.

(d) *Initial certification and recertification procedures.* (1) The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of this part, except that the owner or operator shall meet any additional requirements set forth in an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.

(2) The owner or operator of an affected unit that is not subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart. The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart for any additional NO_x-diluent CEMS, flow monitors, diluent monitors or NO_x concentration monitoring system required under the NO_x mass emissions provisions of § 75.71 or the common stack provisions in § 75.72.

(e) *Quality assurance and quality control requirements.* For units that use continuous emission monitoring systems to account for NO_x mass emissions, the owner or operator shall meet the quality assurance and quality control requirements in § 75.21 that apply to NO_x-diluent continuous emission monitoring systems, flow monitoring systems, NO_x concentration monitoring systems, and diluent monitors under § 75.71. A NO_x concentration monitoring system for determining NO_x mass emissions in accordance with § 75.71 shall meet the same certification testing requirements, quality assurance requirements, and bias test requirements as are specified in this part for an SO₂ pollutant concentration monitor. Units using excepted methods under § 75.19 shall meet the applicable quality assurance requirements of that section, and units using excepted monitoring methods under appendix D and E to this part shall meet the applicable quality

assurance requirements of those appendices.

(f) *Missing data procedures.* Except as provided in § 75.34 and paragraph (g) of this section, the owner or operator shall provide substitute data from monitoring systems required under § 75.71 for each affected unit as follows:

(1) For an owner or operator using a continuous emissions monitoring system, substitute for missing data in accordance with the missing data procedures in subpart D of this part whenever the unit combusts fuel and:

(i) A valid quality assured hour of NO_x emission rate data (in lb/mmBtu) has not been measured and recorded for a unit by a certified NO_x-diluent continuous emission monitoring system or by an approved monitoring system under subpart E of this part;

(ii) A valid quality assured hour of flow data (in scfh) has not been measured and recorded for a unit from a certified flow monitor or by an approved alternative monitoring system under subpart E of this part; or

(iii) A valid quality assured hour of heat input data (in mmBtu) has not been measured and recorded for a unit from a certified flow monitor and a certified diluent (CO₂ or O₂) monitor or by an approved alternative monitoring system under subpart E of this part or by an accepted monitoring system under appendix D to this part, where heat input is required either for calculating NO_x mass or allocating allowances under the applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart; or

(iv) A valid, quality-assured hour of NO_x concentration data (in ppm) has not been measured and recorded by a certified NO_x concentration monitoring system, or by an approved alternative monitoring method under subpart E of this part, where the owner or operator chooses to use a NO_x concentration monitoring system with a volumetric flow monitor, and without a diluent monitor, to calculate NO_x mass emissions. The initial missing data procedures for determining monitor data availability and the standard missing data procedures for a NO_x concentration monitoring system shall be the same as the procedures specified for a NO_x-diluent continuous emission monitoring system under §§ 75.31, 75.32 and 75.33, except that the phrase "NO_x concentration monitoring system" shall be substituted for the phrase "NO_x continuous emission monitoring system", the phrase "NO_x concentration" shall be substituted for "NO_x emission rate"; and the phrase "maximum potential NO_x

concentration, as defined in section 2.1.2.1 of appendix A of this part" shall be substituted for the phrase "maximum potential NO_x emission rate, as defined in § 72.2 of this chapter".

(2) For an owner or operator using an excepted monitoring system under appendix D or E of this part, substitute for missing data in accordance with the missing data procedures in section 2.4 of appendix D to this part or in section 2.5 of appendix E to this part whenever the unit combusts fuel and:

(i) A valid, quality-assured hour of fuel flow rate data has not been measured and recorded by a certified fuel flowmeter that is part of an excepted monitoring system under appendix D or E of this part; or

(ii) A fuel sample value for gross calorific value, or if necessary, density or specific gravity, from a sample taken and analyzed in accordance with appendix D of this part is not available; or

(iii) A valid, quality-assured hour of NO_x emission rate data has not been obtained according to the procedures and specifications of appendix E to this part.

(g) *Reporting data prior to initial certification.* If the owner or operator of an affected unit has not successfully completed all certification tests required by the State or federal NO_x mass emission reduction program that adopts the requirements of this subpart by the applicable date required by that program, he or she shall determine, record and report hourly data prior to initial certification using one of the following procedures, consistent with the monitoring equipment to be certified:

(1) For units that the owner or operator intends to monitor for NO_x mass emissions using NO_x emission rate and heat input, the maximum potential NO_x emission rate and the maximum potential hourly heat input of the unit, as defined in § 72.2 of this chapter.

(2) For units that the owner or operator intends to monitor for NO_x mass emissions using a NO_x concentration monitoring system and a flow monitoring system, the maximum potential concentration of NO_x and the maximum potential flow rate of the unit under section 2.1 of Appendix A of this part;

(3) For any unit, the reference methods under § 75.22 of this part.

(4) For any unit using the low mass emission excepted monitoring methodology under § 75.19, the procedures in paragraphs (g)(1) or (2) of this section.

(5) Any unit using the procedures in paragraph (g)(2) of this section that is

required to report heat input for purposes of allocating allowances shall also report the maximum potential hourly heat input of the unit, as defined in § 72.2 of this chapter.

(h) *Petitions.* (1) The designated representative of an affected unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart. Use of an alternative to any requirement of this subpart is in accordance with this subpart and with such State or federal NO_x mass emission reduction program only to the extent that the petition is approved by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (h)(1) of this section, petitions requesting an alternative to a requirement concerning any additional CEMS required solely to meet the common stack provisions of § 75.72 shall be submitted to the permitting authority and the Administrator and shall be governed by paragraph (h)(3)(ii) of this section. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.

(3)(i) The designated representative of an affected unit that is not subject to an Acid Rain emissions limitation may submit a petition to the permitting authority and the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.

(ii) Use of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that it is approved by the Administrator and by the permitting authority if required by an applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart.

§ 75.71 Specific provisions for monitoring NO_x emission rate and heat input for the purpose of calculating NO_x mass emissions.

(a) *Coal-fired units.* The owner or operator of a coal-fired affected unit shall either:

(1) Meet the general operating requirements in § 75.10 for a NO_x-diluent continuous emission monitoring system (consisting of a NO_x pollutant concentration monitor, an O₂- or CO₂-diluent gas monitor, and a data acquisition and handling system) to measure NO_x emission rate and for a flow monitoring system and an O₂- or CO₂-diluent gas monitor to measure heat input, except as provided in accordance with subpart E of this part; or

(2) Meet the general operating requirements in § 75.10 for a NO_x concentration monitoring system (consisting of a NO_x pollutant concentration monitor and a data acquisition and handling system) to measure NO_x concentration and for a flow monitoring system. In addition, if heat input is required to be reported under the applicable State or federal NO_x mass emission reduction program that adopts the requirements of this subpart, the owner or operator also must meet the general operating requirements for a flow monitoring system and an O₂- or CO₂-diluent gas monitor to measure heat input, or, if applicable, use the procedures in appendix D to this part. These requirements must be met, except as provided in accordance with subpart E of this part.

(b) *Moisture correction.* If a correction for the stack gas moisture content is needed to properly calculate the NO_x emission rate in lb/mmBtu (i.e., if the NO_x pollutant concentration monitor measures on a different moisture basis from the diluent monitor) or NO_x mass emissions in tons (i.e., if the NO_x concentration monitoring system or diluent monitor measures on a different moisture basis from the flow rate monitor), the owner or operator of an affected unit shall account for the moisture content of the flue gas on a continuous basis in accordance with § 75.11(b) except that the term "SO₂" shall be replaced by the term "NO_x".

(c) *Gas-fired nonpeaking units or oil-fired nonpeaking units.* The owner or operator of an affected unit that, based on information submitted by the designated representative in the monitoring plan, qualifies as a gas-fired or oil-fired unit but not as a peaking unit, as defined in § 72.2 of this chapter, shall either:

(1) Meet the requirements of paragraph (a) of this section and, if applicable, paragraph (b) of this section; or

(2) Meet the general operating requirements in § 75.10 for a NO_x-diluent continuous emission monitoring system, except as provided in accordance with subpart E of this part, and use the procedures specified in

appendix D to this part for determining hourly heat input. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_x mass reporting provisions of this subpart, except as provided in § 75.72(a); or

(3) Meet the requirements of the low mass emission excepted methodology under paragraph (e)(2) of this section and under § 75.19, if applicable.

(d) *Gas-fired or oil-fired peaking units.* The owner or operator of an affected unit that qualifies as a peaking unit and as either gas-fired or oil-fired, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan, shall either:

(1) Meet the requirements of paragraph (c) of this section; or

(2) Use the procedures in appendix D to this part for determining hourly heat input and the procedures specified in appendix E to this part for estimating hourly NO_x emission rate. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_x mass reporting provisions of this subpart except for units using an excepted monitoring system under appendix E to this part and except as provided in § 75.72(a). In addition, if after certification of an excepted monitoring system under appendix E to this part, a unit's operations exceed a capacity factor of 20.0 percent in any calendar year or exceed a capacity factor of 10.0 percent averaged over three years, the owner or operator shall meet the requirements of paragraph (c) of this section or, if applicable, paragraph (e) of this section, by no later than December 31 of the following calendar year.

(e) *Low mass emissions units.* Notwithstanding the requirements of paragraphs (c) and (d) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) shall comply with one of the following:

(1) Meet the applicable requirements specified in paragraphs (c) or (d) of this section; or

(2) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly emission rate, hourly heat input, and hourly NO_x mass emissions.

(f) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other materials shall comply with the monitoring provisions specified in paragraph (a) of this section and, where applicable, paragraph (b) of this section.

§ 75.72 Determination of NO_x mass emissions.

Except as provided in paragraphs (e) and (f) of this section, the owner or operator of an affected unit shall calculate hourly NO_x mass emissions (in lbs) by multiplying the hourly NO_x emission rate (in lbs/mmBtu) by the hourly heat input (in mmBtu/hr) and the hourly operating time (in hr). The owner or operator shall also calculate quarterly and cumulative year-to-date NO_x mass emissions and cumulative NO_x mass emissions for the ozone season (in tons) by summing the hourly NO_x mass emissions according to the procedures in section 8 of appendix F to this part.

(a) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:

(1) Record the combined NO_x mass emissions for the units exhausting to the common stack, install, certify, operate, and maintain a NO_x-diluent continuous emissions monitoring system in the common stack, and either:

(i) Install, certify, operate, and maintain a flow monitoring system at the common stack. The owner or operator also shall provide heat input values for each unit, either by monitoring each unit individually using a flow monitor and a diluent monitor or by apportioning heat input according to the procedures in § 75.16(e)(5); or

(ii) If any of the units using the common stack are eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to this part to determine heat input for that unit; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining unit; or

(2) Install, certify, operate, and maintain a NO_x-diluent continuous emissions monitoring system in the duct to the common stack from each unit and either:

(i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each unit; or

(ii) For any unit using the common stack and eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to determine heat input for that unit; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining unit.

(b) *Unit utilizing common stack with nonaffected unit(s).* When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x-diluent continuous emission monitoring system in the duct to the common stack from each affected unit; and

(i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each affected unit; or

(ii) For any affected unit using the common stack and eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to determine heat input for that unit; however, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_x mass reporting provisions of this subpart; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining affected unit that exhausts to the common stack; or

(2) Install, certify, operate, and maintain a NO_x-diluent continuous emission monitoring system in the common stack; and

(i) Designate the nonaffected units as affected units in accordance with the applicable State or federal NO_x mass emissions reduction program and meet the requirements of paragraph (a)(1) of this section; or

(ii) Install, certify, operate, and maintain a flow monitoring system in the common stack and a NO_x-diluent continuous emission monitoring system in the duct to the common stack from each nonaffected unit. The designated representative shall submit a petition to the permitting authority and the Administrator to allow a method of calculating and reporting the NO_x mass emissions from the affected units as the difference between NO_x mass emissions measured in the common stack and NO_x mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly value less than zero. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_x mass emissions from the affected units are not underestimated. In addition, the owner or operator shall also either:

(A) Install, certify, operate, and maintain a flow monitoring system in the duct from each nonaffected unit or,

(B) For any nonaffected unit exhausting to the common stack and otherwise eligible to use the procedures in appendix D to this part, determine heat input using the procedures in appendix D for that unit. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_x mass reporting provisions of this subpart. For any remaining nonaffected unit that exhausts to the common stack, install, certify, operate, and maintain a flow monitoring system in the duct to the common stack; or

(iii) Install a flow monitoring system in the common stack and record the combined emissions from all units as the combined NO_x mass emissions for the affected units for recordkeeping and compliance purposes; or

(iv) Submit a petition to the permitting authority and the Administrator to allow use of a method for apportioning NO_x mass emissions measured in the common stack to each of the units using the common stack and for reporting the NO_x mass emissions. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_x mass emissions from the affected units are not underestimated.

(c) *Unit with bypass stack.* Whenever any portion of the flue gases from an affected unit can be routed to avoid the installed NO_x-diluent continuous emissions monitoring system or NO_x concentration monitoring system, the owner and operator shall either:

(1) Install, certify, operate, and maintain a NO_x-diluent continuous emissions monitoring system and a flow monitoring system on the bypass flue, duct, or stack gas stream and calculate NO_x mass emissions for the unit as the sum of the emissions recorded by all required monitoring systems; or

(2) Monitor NO_x mass emissions on the bypass flue, duct, or stack gas stream using the reference methods in § 75.22(b) for NO_x concentration, flow, and diluent, or NO_x concentration and flow, and calculate NO_x mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems.

(d) *Unit with multiple stacks.* Notwithstanding § 75.17(c), when the flue gases from a affected unit discharge to the atmosphere through more than one stack, or when the flue gases from a unit subject to a NO_x mass emission

reduction program utilize two or more ducts feeding into two or more stacks (which may include flue gases from other affected or nonaffected unit(s)), or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x-diluent continuous emission monitoring system and a flow monitoring system in each duct feeding into the stack or stacks and determine NO_x mass emissions from each affected unit using the stack or stacks as the sum of the NO_x mass emissions recorded for each duct; or

(2) Install, certify, operate, and maintain a NO_x-diluent continuous emissions monitoring system and a flow monitoring system in each stack, and determine NO_x mass emissions from the affected unit using the sum of the NO_x mass emissions recorded for each stack, except that where another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable requirements of paragraphs (a) and (b) of this section to determine and record NO_x mass emissions from the units using that stack; or

(3) If the unit is eligible to use the procedures in appendix D to this part, install, certify, operate, and maintain a NO_x-diluent continuous emissions monitoring system in one of the ducts feeding into the stack or stacks and use the procedures in appendix D to this part to determine heat input for the unit, provided that:

(i) There are no add-on NO_x controls at the unit;

(ii) The unit is not capable of emitting solely through an unmonitored stack (e.g., has no dampers); and

(iii) The owner or operator of the unit demonstrates to the satisfaction of the permitting authority and the Administrator that the NO_x emission rate in the monitored duct or stack is representative of the NO_x emission rate in each duct or stack.

(e) *Units using a NO_x concentration monitoring system and a flow monitoring system to determine NO_x mass.* The owner or operator may use a NO_x concentration monitoring system and a flow monitoring system to determine NO_x mass emissions in paragraphs (a) through (d) of this section (in place of a NO_x-diluent continuous emission monitoring system and a flow monitoring system). When using this approach, calculate NO_x mass according to sections 8.2 and 8.3 in appendix F of this part. In addition, if an applicable

State or federal NO_x mass reduction program requires determination of a unit's heat input, the owner or operator must either:

(1) Install, certify, operate, and maintain a CO₂ or O₂ diluent monitor in the same location as each flow monitoring system. In addition, the owner or operator must provide heat input values for each unit utilizing a common stack by either:

(i) Apportion heat input from the common stack to each unit according to § 75.16(e)(5), where all units utilizing the common stack are affected units, or

(ii) Measure heat input from each affected unit, using a flow monitor and a CO₂ or O₂ diluent monitor in the duct from each affected unit; or

(2) For units that are eligible to use appendix D to this part, use the procedures in appendix D to this part to determine heat input for the unit. However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of appendix D of this part are not applicable to any unit that is using the provisions of this subpart to monitor, record, and report NO_x mass emissions under a State or federal NO_x mass emission reduction program and that shares a common pipe or a common stack with a nonaffected unit.

(f) *Units using the low mass emitter excepted methodology under § 75.19.* For units that are using the low mass emitter excepted methodology under § 75.19, calculate ozone season NO_x mass emissions by summing all of the hourly NO_x mass emissions in the ozone season, as determined under paragraph § 75.19(c)(4)(ii)(A) of this section, divided by 2000 lb/ton.

(g) *Procedures for apportioning heat input to the unit level.* If the owner or operator of a unit using the common stack monitoring provisions in paragraphs (a) or (b) of this section does not monitor and record heat input at the unit level and the owner or operator is required to do so under an applicable State or federal NO_x mass emission reduction program, the owner or operator should apportion heat input from the common stack to each unit according to § 75.16(e)(5).

§ 75.73 Recordkeeping and reporting. **[Reserved]**

§ 75.74 Annual and ozone season monitoring and reporting requirements.

(a) *Annual monitoring requirement.*

(1) The owner or operator of an affected unit subject both to an Acid Rain emission limitation and to a State or federal NO_x mass reduction program that adopts the provisions of this part

must meet the requirements of this part during the entire calendar year.

(2) The owner or operator of an affected unit subject to a State or federal NO_x mass reduction program that adopts the provisions of this part and that requires monitoring and reporting of hourly emissions on an annual basis must meet the requirements of this part during the entire calendar year.

(b) *Ozone season monitoring requirements.* The owner or operator of an affected unit that is not required to meet the requirements of this subpart on an annual basis under paragraph (a) of this section may either:

(1) Meet the requirements of this subpart on an annual basis; or

(2) Meet the requirements of this part during the ozone season, except as specified in paragraph (c) of this section.

(c) If the owner or operator of an affected unit chooses to meet the requirements of this subpart on less than an annual basis in accordance with paragraph (b)(2) of this section, then:

(1) The owner or operator of a unit that uses continuous emissions monitoring systems to meet any of the requirements of this subpart must perform recertification testing of all continuous emission monitoring systems under § 75.20(b). If the owner or operator has not successfully completed all recertification tests by the first hour of unit operation during the ozone season each year, the owner or operator must substitute for data following the procedures of § 75.20(b).

(2) The owner or operator is required to operate and maintain continuous emission monitoring systems and perform quality assurance and quality control procedures under § 75.21 and appendix B of this part each year from the time the continuous emission monitoring system is initially certified or is recertified under paragraph (c)(1) of this section through September 30. Records related to the quality assurance/quality control program must be kept in a form suitable for inspection on a year-round basis.

(3) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input is required to operate or maintain fuel flowmeters only during the ozone season, except that for purposes of determining the deadline for the next periodic quality assurance test on the fuel flowmeter, the owner or operator shall count all quarters during the year when the fuel flowmeter is used, not just quarters in the ozone season. The owner or operator shall record and the designated representative shall report

the number of quarters when a fuel is combusted for each fuel flowmeter.

(4) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input is only required to sample fuel during the ozone season, except that:

(i) The owner or operator of a diesel-fired unit that performs sampling from the fuel storage tank upon delivery must sample the tank between the date and hour of the most recent delivery before the first date and hour that the unit operates in the ozone season and the first date and hour that the unit operates in the ozone season.

(ii) The owner or operator of a diesel-fired unit that performs sampling upon delivery from the delivery vehicle must ensure that all shipments received during the calendar year are sampled.

(iii) The owner or operator of a unit that performs sampling on each day the unit combusts fuel oil or that performs oil sampling continuously must sample the fuel oil starting on the first day the unit operates during the ozone season. The owner or operator then shall use that sampled value for all hours of combustion during the first day of unit operation, continuing until the date and hour of the next sample.

(5) The owner or operator is required to record and report the hourly data required by this subpart for the longer of:

(i) The period of time that the owner or operator of the unit is required to perform the quality assurance and quality control procedures of § 75.21 and appendix B of this part under paragraph (c)(2) of this section; or

(ii) The period of time of May 1 through September 30.

(6) The owner or operator shall use quality-assured data, in accordance with paragraph (c)(2) or (c)(3) of this section, in the substitute data procedures under subpart D of this part and section 2.4 of appendix D of this part.

(i) The lookback periods (e.g., 2160 quality-assured monitor operating hours for a NO_x-diluent continuous emission monitoring system, a NO_x concentration monitoring system, or a flow monitoring system) used to calculate missing data must include only data from periods when the monitors were quality assured under paragraph (c)(2) or (c)(3) of this section.

(ii) If the NO_x emission rate or NO_x concentration of the unit was consistently lower in the previous ozone season because the unit combusted a fuel that produces less NO_x than the fuel currently being combusted or because the unit's add-on emission controls are not operating properly, then the owner or operator shall not use the

missing data procedures of §§ 75.31 through 75.33. Instead, the owner or operator shall substitute the maximum potential NO_x emission rate, as defined in § 72.2 of this chapter, from a NO_x-diluent continuous emission monitoring system, or the maximum potential concentration of NO_x, as defined in section 2.1.2.1 of appendix A to this part, from a NO_x concentration monitoring system. The owner or operator shall substitute these maximum potential values for each hour of missing NO_x data, from completion of recertification testing until the earliest of:

(A) 720 quality-assured monitor operating hours after the completion of recertification testing (not to go beyond September 30 of that ozone season), or
(B) For a unit that changed fuels, the first hour when the unit combusts a fuel that produces the same or less NO_x than the fuel combusted in the previous ozone season, or

(C) For a unit with add-on emission controls that are not operating properly, the first hour when the add-on emission controls operate properly.

(7) The owner or operator of a unit with NO_x add-on emission controls or a unit capable of combusting more than one fuel shall keep records during ozone season in a form suitable for inspection to demonstrate that the typical NO_x emission rate or NO_x concentration during the prior ozone season(s) included in the missing data lookback period is representative of the ozone season in which missing data are substituted and that use of the missing data procedures will not systematically underestimate NO_x mass emissions. These records shall include:

(i) For units that can combust more than one fuel, the fuel or fuels combusted each hour; and

(ii) For units with add-on emission controls, the range of operating parameters for add-on emission controls, as described in § 75.34(a) and information for verifying proper operation of the add-on emission controls, as described in § 75.34(d).

(8) The designated representative shall certify with each quarterly report that NO_x emission rate values or NO_x concentration values substituted for missing data under subpart D of this part are calculated using only values from an ozone season, that substitute values measured during the prior ozone season(s) included in the missing data lookback period are representative of the ozone season in which missing data are substituted, and that NO_x emissions are not systematically underestimated.

(9) Units may qualify to use the low mass emission excepted monitoring

methodology in § 75.19 on an ozone season basis. In order to be allowed to use this methodology, a unit may not emit more than 25 tons of NO_x per ozone season. The owner or operator of the unit shall meet the requirements of § 75.19, with the following exceptions:

(i) The phrase "50 tons of NO_x annually" shall be replaced by the phrase "25 tons of NO_x during the ozone season."

(ii) If any low mass emission unit fails to provide a demonstration that its ozone season NO_x mass emissions are less than 25 tons, than the unit is disqualified from using the methodology. The owner or operator must install and certify any equipment needed to ensure that the unit is monitoring using an acceptable methodology by May 1 of the following year.

(10) Units may qualify to use the optional NO_x mass emissions estimation protocol for gas-fired peaking units and oil-fired peaking units in appendix E to this part on an ozone season basis. In order to be allowed to use this methodology, the unit must meet the definition of peaking unit in § 72.2 of this part, except that the word "calendar year" shall be replaced by the word "ozone season" and the word annual in the definition of the term "capacity factor" in § 72.2 of this part, shall be replaced by the word "ozone season".

§ 75.75 Additional ozone season calculation procedures for special circumstances.

(a) The owner or operator of a unit that is required to calculate ozone season heat input for purposes of providing data needed for determining allocations, shall do so by summing the unit's hourly heat input determined according to the procedures in this part for all hours in which the unit operated during the ozone season.

(b) The owner or operator of a unit that is required to determine ozone season NO_x emission rate (in lbs/mmBtu) shall do so by dividing ozone season NO_x mass emissions (in lbs) determined in accordance with this subpart, by heat input determined in accordance with paragraph (a) of this section.

17. Section 3 of appendix A to part 75 is amended by revising the title of section 3.3.2 and by adding and reserving section 3.3.6, by adding new section 3.3.7 and by revising section 3.4.1 to read as follows:

APPENDIX A TO PART 75—SPECIFICATIONS AND TEST PROCEDURES

* * * * *

3. PERFORMANCE SPECIFICATIONS

* * * * *

3.3.2 RELATIVE ACCURACY FOR NO_x DILUENT CONTINUOUS EMISSION MONITORING SYSTEMS

* * * * *

3.3.6 [Reserved]

3.3.7 RELATIVE ACCURACY FOR NO_x CONCENTRATION MONITORING SYSTEMS

The following requirement applies only to NO_x concentration monitoring systems (i.e., NO_x pollutant concentration monitors) that are used to determine NO_x mass emissions, where the owner or operator elects to monitor and report NO_x mass emissions using a NO_x concentration monitoring system and a flow monitoring system.

The relative accuracy for NO_x concentration monitoring systems shall not exceed 10.0 percent.

* * * * *

3.4.1 SO₂ POLLUTANT CONCENTRATION MONITORS, NO_x CONCENTRATION MONITORING SYSTEMS AND NO_x-DILUENT CONTINUOUS EMISSION MONITORING SYSTEMS

SO₂ pollutant concentration monitors and NO_x emission rate continuous emissions monitoring systems shall not be biased low as determined by the test procedure in section 7.6 of this appendix. NO_x concentration monitoring systems used to determine NO_x mass emissions, as defined in § 75.71, shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all SO₂ pollutant concentration monitors, including those measuring an average SO₂ concentration of 250.0 ppm or less, and to all NO_x-diluent continuous emission monitoring systems, including those measuring an average NO_x emission rate of 0.20 lb/mmBtu or less.

* * * * *

18. Section 6 of appendix A to part 75 is amended by revising the first sentence of the introductory text of section 6.5 and by adding a new sentence after the first sentence, to read as follows:

* * * * *

6.5 Relative Accuracy and Bias Tests

Perform relative accuracy test audits for each CO₂ and SO₂ pollutant concentration monitor; each NO_x concentration monitoring system used to determine NO_x mass emissions; each O₂ monitor used to calculate heat input or CO₂ concentration; each SO₂-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO₂ emission removal efficiency, from January 1, 1997 through December 31, 1999; each flow monitor; and each NO_x-diluent continuous emission monitoring system. Perform relative accuracy test audits for each NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71(a)(2), using the same general procedures as for CO₂ and

SO₂ pollutant concentration monitors; however, use the reference methods for NO_x concentration listed in section 6.5.10 of this appendix. * * *

* * * * *

19. Section 7 of appendix A is amended by revising the introductory text of section 7.6 and by adding three sentences to the end of section 7.6.5 to read as follows:

* * * * *

7.6 Bias Test and Adjustment Factor

Test the relative accuracy test audit data sets for bias for SO₂ pollutant concentration monitors; flow monitors; NO_x concentration monitoring systems used to determine NO_x mass emissions, as defined in § 75.71 (a)(2); and NO_x-diluent continuous emission monitoring systems using the procedures outlined below.

* * * * *

7.6.5 Bias Adjustment

* * * In addition, use the adjusted NO_x concentration and flow rate values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the NO_x concentration and the flow rate when used to calculate NO_x mass emissions, as specified in subpart H of this part. Do not use an adjusted NO_x concentration value to calculate NO_x emission rate using Equations F-5 or F-6 of Appendix F of this part. When monitoring NO_x emission rate and heat input, use the adjusted NO_x emission rate and flow rate values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the NO_x emission rate and the heat input.

* * * * *

20. Appendix C to part 75 is amended by revising sections 2.1, 2.2.2, 2.2.3, 2.2.5, and 2.2.6 to read as follows:

APPENDIX C TO PART 75—MISSING DATA ESTIMATION PROCEDURES

* * * * *

2.1 Applicability

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_x emission rate (in lb/mmBtu), and NO_x concentration data (in ppm) from NO_x concentration monitoring systems used to determine NO_x mass emissions.

2.2 Procedure

2.2.1 * * *

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_x continuous emission monitoring system (or a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71, for each hour of unit operation record a number, 1 through 10 (or 1 through 20 for flow at common stacks), that identifies the operating load range corresponding to the

integrated hourly gross load of the unit(s) recorded for each unit operating hour.

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_x continuous emission monitoring system (or a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71 and continuing thereafter, the data acquisition and handling system must be capable of calculating and recording the following information for each unit operating hour of missing flow or NO_x data within each identified load range during the shorter of: (1) the previous 2,160 quality assured monitor operating hours (on a rolling basis), or (2) all previous quality assured monitor operating hours.

2.2.3.1 Average of the hourly flow rates reported by a flow monitor, in scfh.

2.2.3.2 The 90th percentile value of hourly flow rates, in scfh.

2.2.3.3 The 95th percentile value of hourly flow rates, in scfh.

2.2.3.4 The maximum value of hourly flow rates, in scfh.

2.2.3.5 Average of the hourly NO_x emission rate, in lb/mmBtu, reported by a NO_x continuous emission monitoring system.

2.2.3.6 The 90th percentile value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.7 The 95th percentile value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.8 The maximum value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.9 Average of the hourly NO_x pollutant concentration, in ppm, reported by a NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71.

2.2.3.10 The 90th percentile value of hourly NO_x pollutant concentration, in ppm.

2.2.3.11 The 95th percentile value of hourly NO_x pollutant concentration, in ppm.

2.2.3.12 The maximum value of hourly NO_x pollutant concentration, in ppm.

2.2.4 * * *

2.2.5 When a bias adjustment is necessary for the flow monitor or the NO_x continuous emission monitoring system (or the NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in § 75.71), apply the adjustment factor to all monitor or continuous emission monitoring system data values placed in the load ranges.

2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_x emission rate data (and where applicable, NO_x concentration data) according to the procedures in subpart D of this part.

* * * * *

21. Section 2 of appendix D to part 75 is amended by revising the introductory text of section 2.1.2 to read as follows:

APPENDIX D TO PART 75—OPTIONAL SO₂ EMISSIONS DATA PROTOCOL FOR GAS-FIRED AND OIL-FIRED UNITS

* * * * *

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in

a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (i.e., a pipe carrying fuel for multiple units). However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of this appendix are not applicable to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO_x mass emissions under a State or federal NO_x mass emission reduction program, except as provided in § 75.72(a) for units with a NO_x CEMS installed in a common stack or except as provided for units monitored with an excepted monitoring system under appendix E to this part. For all other units, if the fuel flowmeter is installed in a common pipe header, do one of the following:

* * * * *

22. Section 8 of appendix F to part 75 is added to read as follows:

APPENDIX F TO PART 75—CONVERSION PROCEDURES

* * * * *

8. Procedures for NO_x Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO_x mass emissions under a State or federal NO_x mass emission reduction program must use the procedures in section 8.1 to account for hourly NO_x mass emissions, and the procedures in section 8.2 to account for quarterly, seasonal, and annual NO_x mass emissions to the extent that the provisions of subpart H of this part are adopted as requirements under such a program.

8.1 Use the following procedures to calculate hourly NO_x mass emissions in lbs for the hour using hourly NO_x emission rate and heat input.

8.1.1 If both NO_x emission rate and heat input are monitored at the same unit or stack level (e.g., the NO_x emission rate value and heat input value both represent all of the units exhausting to the common stack), use the following equation:

$$M_{(NO_x)_h} = E_{(NO_x)_h} HI_h t_h \quad (\text{Eq. F-24})$$

where:

$M_{(NO_x)_h}$ = NO_x mass emissions in lbs for the hour.

$E_{(NO_x)_h}$ = Hourly average NO_x emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from method 19 of appendix A to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_x emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

t_h = Monitoring location operating time for hour h , in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the combined NO_x emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack.

8.1.2 If NO_x emission rate is measured at a common stack and heat input is measured at the unit level, sum the hourly heat inputs at the unit level according to the following formula:

$$HI_{CS} = \frac{\sum_{u=1}^p HI_u t_u}{t_{CS}} \quad (\text{Eq. F-25})$$

where:

HI_{CS} = Hourly average heat input rate for hour h for the units at the common stack, mmBtu/hr.

t_{CS} = Common stack operating time for hour h , in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator) (e.g., total time when any of the units which exhaust through the common stack are operating).

HI_u = Hourly average heat input rate for hour h for the unit, mmBtu/hr.

t_u = Unit operating time for hour h , in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

Use the hourly heat input rate at the common stack level and the hourly average NO_x emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly NO_x mass emissions at the common stack.

8.1.3 If a unit has multiple ducts and NO_x emission rate is only measured at one duct, use the NO_x emission rate measured at the duct, the heat input measured for the unit, and the procedures in section 8.1.1 of this appendix to determine NO_x mass emissions.

8.1.4 If a unit has multiple ducts and NO_x emission rate is measured in each duct, heat input shall also be measured in each duct and the procedures in section 8.1.1 of this appendix shall be used to determine NO_x mass emissions.

8.2 If a unit calculates NO_x mass emissions using a NO_x concentration monitoring system and a flow monitoring system, calculate hourly NO_x mass rate during unit (or stack) operation, in lb/hr, using Equation F-1 or F-2 in this appendix (as applicable to the moisture basis of the monitors). When using Equation F-1 or F-2, replace " SO_2 " with " NO_x " and replace the value of K with 1.194×10^{-7} (lb NO_x /scf)/ppm. (Include bias-adjusted flow rate or NO_x concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

8.3 If a unit calculates NO_x mass emissions using a NO_x concentration monitoring system and a flow monitoring system, calculate NO_x mass emissions for the hour (lb) by multiplying the hourly NO_x mass emission rate during unit operation (lb/hr) by the unit operating time during the hour, as follows:

$$M_{(\text{NO}_x)_h} = E_h t_h \quad (\text{Eq. F-26})$$

Where:

$M_{(\text{NO}_x)_h}$ = NO_x mass emissions in lbs for the hour.

E_h = Hourly NO_x mass emission rate during unit (or stack) operation, lb/hr, from section 8.2 of this appendix.

t_h = Monitoring location operating time for hour h , in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the NO_x mass emission rate is monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack.

8.4 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO_x mass emissions, in tons:

$$M_{(\text{NO}_x)_{\text{time period}}} = \frac{\sum_{h=1}^p M_{(\text{NO}_x)_h}}{2000} \quad (\text{Eq. F-27})$$

Where:

$M_{(\text{NO}_x)_{\text{time period}}}$ = NO_x mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(\text{NO}_x)_h}$ = NO_x mass emissions in lbs for the hour. p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

8.5 *Specific provisions for monitoring NO_x mass emissions from common stacks.* The owner or operator of a unit utilizing a common stack may account for NO_x mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a State or federal NO_x mass reduction program:

8.5.1 The owner or operator may determine both NO_x emission rate and heat input at the common stack and use the procedures in section 8.1.1 of this appendix to determine hourly NO_x mass emissions at the common stack.

8.5.2 The owner or operator may determine the NO_x emission rate at the common stack and the heat input at each of the units and use the procedures in section 8.1.2 of this appendix to determine the hourly NO_x mass emissions at each unit.

23. Part 96 is added to read as follows:

PART 96— NO_x Budget Trading Program for State Implementation Plans

Subpart A— NO_x Budget Trading Program General Provisions

Sec.

96.1 Purpose.

96.2 Definitions.

96.3 Measurements, abbreviations, and acronyms.

96.4 Applicability.

96.5 Retired unit exemption.

96.6 Standard requirements.

96.7 Computation of time.

Subpart B—Authorized Account Representative for NO_x Budget Sources

96.10 Authorization and responsibilities of the NO_x authorized account representative.

96.11 Alternate NO_x authorized account representative.

96.12 Changing the NO_x authorized account representative and the alternate NO_x authorized account representative; changes in the owners and operators.

96.13 Account certificate of representation.

96.14 Objections concerning the NO_x authorized account representative.

Subpart C—Permits

96.20 General NO_x Budget permit requirements.

96.21 Submission of NO_x Budget permit applications.

96.22 Information requirements for NO_x Budget permit applications.

96.23 NO_x Budget permit contents.

96.24 Effective date of initial NO_x Budget permit.

96.25 NO_x Budget permit revisions.

Subpart D—Compliance Certification

96.30 Compliance certification report.

96.31 Permitting authority's and Administrator's action on compliance certifications.

Subpart E— NO_x Allowance Allocations

96.40 State trading program budget.

96.41 Timing requirements for NO_x allowance allocations.

96.42 NO_x allowance allocations.

Subpart F— NO_x Allowance Tracking System

96.50 NO_x Allowance Tracking System accounts.

96.51 Establishment of accounts.

96.52 NO_x Allowance Tracking System responsibilities of NO_x authorized account representative.

96.53 Recordation of NO_x allowance allocations.

96.54 Compliance.

96.55 Banking.

96.56 Account error.

96.57 Closing of general accounts.

The Commission is exempt from Executive Order 12866 and its provisions do not apply to this rule. Even if the Order were applicable, the rule would not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act. The implementation of the rule will have no adverse effect on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic or export markets.

Finally, the Secretary of the Panama Canal Commission certifies these changes meet the applicable standards set out in sections 2(a) and 2(b)(2) of Executive Order 12778.

List of Subjects

35 CFR Part 113

Cargo vessels, Hazardous materials transportation, Reporting and recordkeeping requirements.

35 CFR Part 115

Organization and functions (Government agencies), Panama Canal.

For the reasons stated in the Preamble, the Panama Canal Commission amends 35 CFR Parts 113 and 115 as follows:

PART 113—DANGEROUS CARGOES

1. The authority citation for part 113 is revised to read as follows:

Authority: 22 U.S.C. 3811; EO 12215, 45 FR 36043, 3 CFR 1980 Comp., p. 257.

2. Revise § 113.49(b) to read as follows:

§ 113.49 Class 1, Explosives.

* * * * *

(b) Explosive cargo to be used for other than official U.S. Government purposes may not be loaded or off-loaded at facilities of the Panama Canal Commission. Explosive anchorages prescribed in §§ 101.8(a)(2) and (3) and 101.8(c)(2) of this chapter may be used upon approval of the Marine Safety Advisor, or his designee, and with the concurrence of the Canal Operations Captain.

* * * * *

PART 115—BOARD OF LOCAL INSPECTORS; COMPOSITION AND FUNCTIONS

1. The authority citation for part 115 continues to read as follows:

Authority: 22 U.S.C. 3778; E.O. 12215, 45 FR 36043, 3 CFR 1980 Comp., p. 257.

§ 115.2 [Amended]

2. Amend § 115.2 as follows:

In paragraph (b) remove the word "Administrator" and add, in its place, the words "Marine Operations Director".

Dated: April 10, 1998.

John A. Mills,
Secretary.

[FR Doc. 98-9965 Filed 4-15-98; 8:45 am]

BILLING CODE 3640-04-P

DEPARTMENT OF AGRICULTURE

Forest Service

36 CFR Part 292

RIN 0596-AB39

Smith River National Recreation Area; Correction

AGENCY: Forest Service, USDA.

ACTION: Final rule; correction.

SUMMARY: In the **Federal Register** of March 27, 1998, the Department published a final rule implementing Section 8(d) of the Smith River National Recreation Area Act of 1990. The final rule contained incorrect amendatory language. This document corrects that document.

EFFECTIVE DATE: This correction is effective on April 27, 1998. As noted in the final rule published March 27, 1998, the final rule is effective on April 27, 1998.

FOR FURTHER INFORMATION CONTACT: Betty Anderson, Directives and Regulations Branch, Information Resources Management Staff, Forest Service, (703) 235-2994.

SUPPLEMENTARY INFORMATION: In the March 27, 1998, final rule for the Smith River National Recreation Area, the amendatory language incorrectly stated that a new subpart G was being added to part 292. This document corrects the amendatory language in rule FR Doc. 98-7924 (63 FR 15042, Part III) as follows:

On page 15059, in the second column, in paragraph 5, on line 4, in the amendatory language "amended by adding a new subpart G" is corrected to read "amended by revising subpart G."

Dated: April 10, 1998.

Sandra Key,
Acting Associate Chief.

[FR Doc. 98-10050 Filed 4-15-98; 8:45 am]

BILLING CODE 3410-11-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 74

[FRL-5996-6]

RIN 2060-AH36

Acid Rain Program: Revisions to Sulfur Dioxide Opt-Ins

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Title IV of the Clean Air Act, as amended by Clean Air Act Amendments of 1990, ("Act") authorizes the Environmental Protection Agency ("EPA" or "Agency") to establish the Acid Rain Program. The purpose of the Acid Rain Program is to significantly reduce emissions of sulfur dioxide and nitrogen oxides from electric generating plants in order to reduce the adverse health and ecological impacts of acidic deposition (or acid rain) resulting from such emissions. This final rule is intended to promote participation in the title IV opt-in program by clarifying existing regulations, allowing a limited exception to the general rule of one designated representative for all affected units at a source, revising the conditions under which the Agency may cancel current-year allowance allocations, and allowing thermal energy plans to be effective on a quarterly basis.

DATES: This rule is effective May 18, 1998.

Judicial Review. Under section 307(b)(1) of the Act, judicial review of this rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of these final rule revisions. Under section 307(b)(2) of the Act, the requirements that are the subject of today's document may not be challenged in civil or criminal proceedings brought by the EPA to enforce these requirements.

ADDRESSES: *Docket.* Docket No. A-97-23, containing supporting information used to develop the rule is available for public inspection and copying from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section (6102), Waterside Mall, Room M1500, 1st Floor, 401 M Street, SW, Washington D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Kathy Barylski at (202) 564-9074, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M St., SW, Washington, D.C. 20460; or

the Acid Rain Hotline at (202) 564-9620. Electronic copies of this rulemaking can be accessed through the Acid Rain Division website at www.epa.gov/acidrain.

SUPPLEMENTARY INFORMATION:

- I. Affected Entities
- II. Background
- III. Part 74: Opt-Ins
 - A. Designated Representative
 - B. Thermal Energy Plans
 - C. Deduction of Allowances from ATS Accounts
 - D. Miscellaneous
- IV. Administrative Requirements
 - A. Executive Order 12866
 - B. Unfunded Mandates Act
 - C. Paperwork Reduction Act
 - D. Regulatory Flexibility
 - E. Submission to Congress and the General Accounting Office

I. Affected Entities

Entities potentially affected by this action are fossil fuel fired boilers or turbines that serve generators producing electricity, generate steam, or cogenerate electricity and steam. Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Electric service providers, boilers from a wide range of industries.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities potentially affected by this action. This table lists the types of entities that EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be affected. To determine whether your facility is affected by this action, you should carefully examine the applicability criteria in § 74.2 of title 40 of the Code of Federal Regulations and the revised §§ 72.6, 72.7, 72.8, and 72.14 (62 FR 55460, 55476-80, October 24, 1997). If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

II. Background

The overall goal of the Acid Rain Program is to achieve significant environmental benefits through reductions in emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x), the primary precursors of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and promotes pollution prevention.

The Acid Rain Program departs from traditional regulatory methods by introducing an SO₂ allowance trading system that lowers the cost of reducing emissions by allowing electric utilities to seek out the least costly methods of control. Affected utility units under title IV of the Act are allocated allowances based on formulas in the Act. These units may trade allowances, provided that at the end of each year, each unit holds enough allowances to cover its annual SO₂ emissions.

Although the Acid Rain Program is mandated only for utility sources, section 410 provides opportunities for SO₂-emitting sources not otherwise affected by title IV requirements (e.g., industrial sources) to participate through the opt-in program. Entry of sources into the opt-in program is voluntary. Opt-in sources are allocated allowances and, by making cost-effective emissions reductions so that their allowance allocations will exceed their emissions, will have allowances that may be sold in the SO₂ allowance trading system. These allowances provide greater compliance flexibility for affected units.

In 1995, EPA issued final opt-in regulations implementing section 410 (60 FR 17100, April 4, 1995). On June 5, 1995, an owner of several potential opt-in sources filed a petition for review of the existing opt-in regulations. The litigation was settled on January 9, 1997. On September 25, 1997, EPA proposed opt-in regulation revisions, several of which resulted from that settlement.

III. Part 74: Opt-Ins

A. Designated Representative

Under the existing opt-in rule, combustion or process sources located at the same source as affected units are required to have the same designated representative as the affected utility units. See 40 CFR 74.4(b). (Hereinafter, this requirement is referred to as the "single-designated-representative requirement".) Based on comments and settlement of litigation on the issue, EPA proposed to establish a procedure for nonutility combustion or process sources located with affected utility units to elect an exception to the single-designated-representative requirement.

One comment was received on this proposed revision.¹ The commenter, who is a party to the January 9, 1997 opt-in rule settlement, generally supported allowing a separate

designated representative for opt-in sources at the same source as affected utility units. However, the commenter objected to certain language in the proposed rule.

The proposed rule required that, in order to use the separate designated representative provision, a combustion source must have "no owner of which the principal business is the sale, transmission, or distribution of electricity or that is a public utility under the jurisdiction of a State or local utility regulatory commission." The commenter claimed that the language concerning the principal business of the combustion source owner would bar a combustion source owned by a wholly-owned electric generating subsidiary of an industrial company from using the provision but would allow use of the provision if the source was instead directly owned by the industrial company. According to the commenter, the use of "separate corporate forms" should not have this effect on the ability to have a separate designated representative. The commenter also claimed that, even if a State utility regulatory authority did not currently regulate the wholly-owned electric generating subsidiary, the State authority might assert jurisdiction sometime in the future, thereby preventing use of the provision.

In light of the commenter's objections and in order to reduce the complexity of the separate designated representative provision, EPA is revising, in today's final rule, the proposed provision. On one hand, as discussed in the proposal, the provision is intended to encourage nonutility opt-ins by allowing a nonutility opt-in source located at the same source as utility units to select a different designated representative than the utility units. 62 FR 50457. Because a nonutility opt-in source is part of industrial operations (e.g., produces electricity for use in the owner's industrial facilities), the owner is more likely to have heightened concern about competitive disadvantage and maintaining the confidentiality of information about the opt-in source and related industrial operations. Having a single designated representative for a nonutility opt-in source and utility units may make information (e.g., the industrial company's electricity generating costs and processes using electricity) available to the designated representative, who may be an employee of the utility owner. On the other hand, as discussed in the proposal, EPA believes that generally opt-in sources should face the same requirements as other affected units. *Id.*; see also 58 FR 50088, 50090-91,

¹ One comment received during the comment period for the proposed opt-in revisions addressed a number of matters, but did not comment on any of the proposed opt-in revisions. The comment is therefore outside the scope of this rulemaking.

September 24, 1993. Balancing the importance of imposing consistent requirements on opt-in sources and utility units against the desire to encourage industrial opt-ins, EPA concludes that it should allow only a limited exception—applicable in a few cases—to the single-designated-representative requirement. While the proposal carved out a limited exception using a test focused on the owner (i.e., the nature of, and regulatory jurisdiction over, the owner's principal business) of the opt-in sources, EPA maintains that a simpler approach is available, i.e., one focused on the opt-in source itself. The Acid Rain regulations specifically address four categories of combustion sources that are unaffected units and that therefore may qualify as opt-in sources: (1) combustion devices that have not served, and do not serve, generators producing electricity for sale; (2) simple combustion turbines that commenced operation before November 15, 1990; (3) combustion devices that commenced commercial operation before November 15, 1990 and that have served, and serve, only generators of 25 MWe or less producing electricity for sale; and (4) cogeneration, qualifying, independent power production, or solid waste incineration facilities that meet certain requirements. See 40 CFR 72.6(b) (explaining the categories of unaffected units) and 74.2 (stating that affected units under § 72.6 are not eligible to be opt-in sources). The limited exception to the single-designated-representative requirement is aimed at the first category of combustion source, i.e., units that are part of industrial, not utility operations. No commenter has suggested that the exception should be extended to any other categories of combustion sources.

EPA notes, in addition, that sources other than those in the first category would generally not be eligible for the exception as originally proposed because they would most likely be part of utility operations and the proposal barred sources whose owners are principally in the business of selling, transmitting, or distributing electricity or are subject to State or local utility regulation. Moreover, for the reasons discussed above, EPA maintains that it should limit the exception to the clearest cases where the single-designated-representative requirement may inhibit entry into, or continued participation in, the opt-in program: i.e., the few cases where an opt-in source is co-located with utility units and is involved in industrial, rather than utility (i.e., electricity sales), operations.

Consequently, today's final rule limits the use of the exception to a combustion

source (or process source) that, on the date on which the source's initial opt-in application is submitted and thereafter, does not serve a generator producing electricity for sale. Such a combustion or process source that is located at the same source as affected utility units may elect to have a different designated representative than the utility units. For example, a combustion source that is owned by an industrial company and that is used exclusively to generate electricity for use in the industrial company's industrial facilities could qualify for the exception to the single-designated-representative requirement. Similarly, such a combustion source could qualify even if it is owned by the wholly-owned subsidiary of the industrial company, instead of being owned directly by the industrial company. This approach in today's final rule meets the commenter's concerns that the corporate form of ownership of the source, or law concerning the jurisdiction of the State utility regulatory commission, not change the applicability of the exception to a combustion source that would otherwise qualify for the exception.

With the approach of basing the exception on the fact that a combustion source is not, as of the submission of the initial opt-in permit application and thereafter, serving a generator producing electricity for sale, it is necessary to include a provision for termination of the exception if and when that requirement is no longer met in the future. Today's final rule therefore provides for automatic termination of the election of the exception when the requirements for election are no longer met and requires submission of a superseding certificate of representation consistent with single-designated-representative requirement for all affected units at a given source. This is analogous to the automatic termination provisions for other exceptions under the Acid Rain Program. See 40 CFR 72.7(f)(4) (new units exemption) 72.8(d)(6), (retired units exemption), and 72.14(d)(4) (industrial utility-units exemption).

B. Thermal Energy Plans

The existing opt-in rule allows combustion sources to become opt-in sources at the beginning of any calendar quarter, not only at the beginning of a calendar year. See 40 CFR 74.28. However, in the proposed revisions to the rule, EPA noted that the thermal energy provision at § 74.47 only provided for calendar year plans. Therefore, EPA proposed revisions to allow (and take account of the

possibility of) the submission of thermal energy plans at the beginning of any calendar quarter. No comments were received on these proposed revisions. With one exception, EPA has finalized the proposed revisions for the reasons stated in the proposal.

The only change, in today's final rule, to the proposed revisions is that EPA is not adopting the proposed revisions to paragraph (a)(3)(vii) of § 74.47. The existing rule requires the thermal energy plan to include the "allowable SO₂ emissions rate" for the calendar year in which the plan will take effect. In § 72.2, "allowable SO₂ emissions rate" is defined as the "most stringent federally enforceable emissions limitation for sulfur dioxide * * * for the specified calendar year". 40 CFR 72.2. The proposal added references in § 74.47(a)(3)(vii) to the allowable SO₂ emissions rate for the calendar year and month for which the thermal energy plan will take effect. This change would be inconsistent with the above-quoted definition in § 72.2 and so is not being adopted.

As already provided in the existing rule, if more than one federally enforceable emissions limitation applies during the year, the allowable SO₂ emission rate in § 74.47(a)(3)(vii) will be the most stringent of these limits.

C. Deduction of Allowances From ATS Accounts

For any affected unit, including an opt-in source, EPA draws upon future-year allowances in the affected unit's Allowance Tracking System (ATS) account to offset excess emissions for a year for which compliance is being determined. See 40 CFR 77.5. However, under the existing opt-in rule, when the opt-in source shuts down, is reconstructed, becomes an affected unit under § 72.6, or fails to renew its opt-in permit, EPA eliminates future-year allowance allocations (40 CFR 74.46) and retains the option of canceling current-year opt-in allowance allocations (including allowances that have been transferred to other ATS accounts) in order to offset excess emissions or account for the termination of participation in the opt-in program (40 CFR 74.50). As proposed, EPA is revising the rule to provide that an opt-in allowance may not be deducted under § 74.50(a) from any ATS account, other than the account of the opt-in source allocated such allowance, (i) after EPA has completed the process of recordation as set forth in § 73.34(a) following the deduction of allowances from the opt-in source's compliance subaccount for the year for which such allowance may first be used or (ii) if the

opt-in source claims in an annual compliance certification report an estimated reduction in heat input from improved efficiency, under § 74.44(a)(1)(B), after EPA has completed action on the confirmation report concerning such claimed reduction pursuant to §§ 74.44(c)(2)(iii)(E)(3)–(E)(5) for the year for which such allowance may first be used. No comments were received on this revision, and, for the reasons stated in the proposal, the revision is adopted as proposed.

D. Miscellaneous

EPA proposed a number of modifications and corrections to the combustion source opt-in rules to reflect changes in the Acid Rain Program and operating permits program under title V of the Clean Air Act since the publication of the final opt-in rule on April 4, 1995. In particular, the Agency has finalized the operating permits rule in part 71 and the Acid Rain permit rule in part 72. The proposed modifications and corrections were described in the “Miscellaneous” section of the preamble to the proposal. No comments were received, and the proposed changes are adopted as final.

IV. Administrative Requirements

A. Executive Order 12866

Under Executive Order 12866, 58 FR 51735, October 4, 1993, the Administrator must determine whether a regulatory action is “significant” and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The order defines “significant regulatory action” as one that is likely to result in a rule that may:

- (1) Have an annual effect on the economy of \$100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;
- (2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- (3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- (4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is not a “significant regulatory action.” As such, this action

is not subject to the requirements of the order and was not submitted to OMB for review.

B. Unfunded Mandates Act

Section 202 of the Unfunded Mandates Reform Act of 1995 (“Unfunded Mandates Act”) requires that the Agency prepare a budgetary impact statement before promulgating a rule that includes a federal mandate that may result in expenditure by State, local, and tribal governments, in aggregate, or by the private sector, of \$100 million or more in any one year. Section 203 requires the Agency to establish a plan for obtaining input from and informing, educating, and advising any small governments that may be significantly or uniquely affected by the rule.

Under section 205 of the Unfunded Mandates Act, the Agency must identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a budgetary impact statement must be prepared. The Agency must select from those alternatives the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule, unless the Agency explains why this alternative is not selected or the selection of this alternative is inconsistent with law.

Because this rule is estimated to result in the expenditure by State, local, and tribal governments or the private sector of less than \$100 million in any one year, the Agency has not prepared a budgetary impact statement or specifically addressed the selection of the least costly, most cost-effective, or least burdensome alternative. Because small governments will not be significantly or uniquely affected by this rule, the Agency is not required to develop a plan with regard to small governments.

The revisions to part 74 will not have a significant or unique effect on any regulated entities or State permitting authorities. Moreover, the revisions potentially reduce the burden on certain opt-in sources, by allowing the election of a separate designated representative and by allowing thermal energy plans to begin on the calendar quarter. Also, the revisions potentially reduce the burden on the utility sector by limiting when EPA may deduct allowances from ATS accounts.

C. Paperwork Reduction Act

These revisions to the opt-in rule would not impose any new information collection burden. OMB has previously approved the information collection requirements contained in the opt-in

rules, 40 CFR part 74, under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* and has assigned OMB control number 2060–0258. 60 FR 17111.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to: review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Copies of the original ICR may be obtained from Sandy Farmer, OPPE Regulatory Information Division, U.S. Environmental Protection Agency, 401 M St. SW. (2137), Washington, D.C. 20460 or by calling (202) 260–2740.

D. Regulatory Flexibility

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has also determined that this rule will not have a significant economic impact on a substantial number of small entities. In the preamble of the April 4, 1995 opt-in rule, the Administrator certified that the rule, including the provisions revised by today's rule, would not have a significant economic impact on small entities. 60 FR 17111. Today's revisions are not significant enough to change the overall economic impact addressed in the April 4, 1995 preamble. Moreover, as discussed above, the revisions provide regulated entities with additional flexibility (e.g., the option to have a separate designated representative and to have a thermal energy plan that begins in the second, or later, quarter of the year).

E. Submission to Congress and the General Accounting Office

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a

report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This rule is not a "major rule" as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 74

Environmental protection, Acid rain, Air pollution control, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: April 9, 1998.

Carol M. Browner,
Administrator.

For the reasons set forth in the preamble, 40 CFR part 74 is amended as set forth below.

PART 74—[AMENDED]

1. The authority citation for part 74 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

§ 74.3 [Amended]

2. Section 74.3 is amended by:

- i. In paragraph (b), revising the words "parts 70 and 72" to read "parts 70, 71, and 72";
- ii. In paragraph (b), revising the words "part 70" to read "parts 70 and 71"; and
- iii. Adding at the end of paragraph (d) the words ",consistent with subpart E of this part."

3. Section 74.4 is amended by adding paragraph (c) to read as follows:

§ 74.4 Designated representative.

* * * * *

(c)(1) Notwithstanding paragraph (b) of this section, a certifying official of a combustion or process source that is located at the same source as one or more affected utility units and that, on the date on which an initial opt-in permit application is submitted for such combustion or process source and thereafter, does not serve a generator

that produces electricity for sale may elect to designate, for such combustion or process source, a different designated representative than the designated representative for the affected utility units.

(2) In order to make such an election, the certifying official shall submit to the Administrator, in a format prescribed by the Administrator: a certification that the combustion or process source for which the election is made meets each of the requirements for election in paragraph (c)(1) of this section; and a certificate of representation for the designated representative of the combustion or process source in accordance with § 72.24 of this chapter. The Administrator will rely on such certificate of representation in accordance with § 72.25 of this chapter, unless the Administrator determines that the requirements for election in paragraph (c)(1) of this section are not met. If, after the election is made, the requirements for election in paragraph (c)(1) of this section are no longer met, the election shall automatically terminate on the first date on which the requirements are no longer met and, within 30 days of that date, a certificate of representation for the designated representative of the combustion or process source shall be submitted consistent with paragraph (b) of this section.

§ 74.10 [Amended]

4. Section 74.10 is amended by, in paragraph (a)(2), revising the word "§ 74.62" to read "§ 75.20 of this chapter".

§ 74.14 [Amended]

5. Section 74.14 is amended by:

- i. In paragraph (b) introductory text, revising the words "part 70" to read "parts 70 and 71"; and
- ii. In paragraph (b)(6)(ii), revising the word "approved" to read "approved for operating permits".

§ 74.16 [Amended]

6. Section 74.16 is amended by, in paragraph (a)(12), adding the words "and does not have an exemption under § 72.7, § 72.8, or § 72.14 of this chapter" before the semicolon.

§ 74.18 [Amended]

7. Section 74.18 is amended by:

- i. In paragraph (d), revising the words "§ 74.46(c)" to read "§ 74.46(b)(2)"; and
- ii. Removing the last sentence from paragraph (e).

§ 74.22 [Amended]

8. Section 74.22 is amended by, in paragraph (c)(2), revising the words "§ 74.20(a)(2)(A)" to read "§ 74.20(a)(2)(i)".

§ 74.26 [Amended]

9. Section 74.26 is amended by, in paragraph (a)(2), revising the words "in which" to read "for which".

§ 74.42 [Amended]

10. Section 74.42 is amended by removing from paragraph (a) the word "(a)".

§ 74.44 [Amended]

11. Section 74.44 is amended by:

- i. In paragraph (a)(1)(i)(G), revising the words "demand side measures that improve the efficiency of electricity or steam consumption" to read "specific measures";
- ii. In paragraph (a)(2)(i), removing the words "or for the first two calendar years after the effective date of a thermal energy plan governing an opt-in source in accordance with § 74.47 of this chapter";
- iii. In paragraph (a)(2)(iii), adding the words "of this section" after the word "(a)(2)(ii)";
- iv. In paragraph (c)(2)(ii)(B)(1), revising the words "opt-in sources." to read "opt-in sources and Phase I units.";
- v. In paragraph (c)(2)(iii)(F), revising the formula to read as follows:

$$\text{Allowances allocated or acquired} - \text{tons emitted} - \text{the larger of} \left(\begin{array}{l} \text{allowances transferred} \\ \text{to all replacement units} \\ \text{or} \\ \text{allowances deducted} \\ \text{for reduced utilization} \end{array} \right)$$

vi. In paragraph (c)(2)(iii)(F), revising the words "'Allowances allocated' shall be the original number of allowances allocated under section § 74.40 for the calendar year." to read "'Allowances allocated or acquired' shall be the number of allowances held in the source's compliance subaccount at the

allowance transfer deadline plus the number of allowances transferred for the previous calendar year to all replacement units under an approved thermal energy plan in accordance with § 74.47(a)(6)."; and

vii. In paragraph (c)(2)(iii)(E)(3), revising the words "allowances

necessary" to read "allowances that he or she determines is necessary".

12. Section 74.47 is amended by:

- i. Adding in paragraph (a)(3)(i), after the word "year" in each place it appears, the word "and quarter"; and

ii. Revising paragraphs (a)(1), (a)(3)(viii), (a)(3)(ix), (a)(3)(x), (a)(3)(xi), (a)(3)(xii), and (a)(4) to read as follows:

§ 74.47 Transfer of allowances from the replacement of thermal energy—combustion sources.

(a) Thermal energy plan. (i) General provisions. The designated representative of an opt-in source that seeks to qualify for the transfer of allowances based on the replacement of thermal energy by a replacement unit shall submit a thermal energy plan subject to the requirements of § 72.40(b) of this chapter for multi-unit compliance options and this section. The effective period of the thermal energy plan shall begin at the start of the calendar quarter (January 1, April 1, July 1, or October 1) for which the plan is approved and end December 31 of the last full calendar year for which the opt-in permit containing the plan is in effect.

* * * * *

(3) * * *

(viii) The estimated annual amount of total thermal energy to be reduced at the opt-in source, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application, and, for a plan starting April 1, July 1, or October 1, such estimated amount of total thermal energy to be reduced starting April 1, July 1, or October 1 respectively and ending on December 31;

(ix) The estimated amount of total thermal energy at each replacement unit for the calendar year prior to the year for which the plan is to take effect, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application, and, for a plan starting April 1, July 1, or October 1, such estimated amount of total thermal energy for the portion of such calendar year starting April 1, July 1, or October 1 respectively;

(x) The estimated annual amount of total thermal energy at each replacement unit after replacing thermal energy at the opt-in source, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application, and, for a plan starting April 1, July 1, or October 1, such estimated amount of total thermal energy at each replacement unit after replacing thermal energy at the opt-in source starting April 1, July 1, or October 1 respectively and ending December 31;

(xi) The estimated annual amount of thermal energy at each replacement unit, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application,

replacing thermal energy at the opt-in source, and, for a plan starting April 1, July 1, or October 1, such estimated amount of thermal energy replacing thermal energy at the opt-in source starting April 1, July 1, or October 1 respectively and ending December 31;

(xii) The estimated annual total fuel input at each replacement unit after replacing thermal energy at the opt-in source and, for a plan starting April 1, July 1, or October 1, such estimated total fuel input after replacing thermal energy at the opt-in source starting April 1, July 1, or October 1 respectively and ending December 31;

* * * * *

(4) *Submission.* The designated representative of the opt-in source seeking to qualify for the transfer of allowances based on the replacement of thermal energy shall submit a thermal energy plan to the permitting authority by no later than six months prior to the first calendar quarter for which the plan is to be in effect. The thermal energy plan shall be signed and certified by the designated representative of the opt-in source and each replacement unit covered by the plan.

* * * * *

13. Section 74.50 is amended by redesignating the introductory text of paragraph (a) as paragraph (a)(1), redesignating paragraphs (a)(1) through (a)(4) as paragraphs (a)(1)(i) through (a)(1)(iv), and adding paragraph (a)(2) to read as follows:

§ 74.50 Deducting opt-in source allowances from ATS accounts.

(a) * * *

(2) An opt-in allowance may not be deducted under paragraph (a)(1) of this section from any Allowance Tracking System Account other than the account of the opt-in source allocated such allowance:

(i) After the Administrator has completed the process of recordation as set forth in § 73.34(a) of this chapter following the deduction of allowances from the opt-in source's compliance subaccount for the year for which such allowance may first be used; or

(ii) If the opt-in source includes in the annual compliance certification report estimates of any reduction in heat input resulting from improved efficiency under § 74.44(a)(1)(i), after the Administrator has completed action on the confirmation report concerning such estimated reduction pursuant to § 74.44(c)(2)(iii)(E)(3), (4), and (5) for the

year for which such allowance may first be used.

* * * * *

[FR Doc. 98-10143 Filed 4-15-98; 8:45 am]

BILLING CODE 6560-50-P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 97-118; RM-9061]

Radio Broadcasting Services; Pentwater and Walhalla, MI

AGENCY: Federal Communications Commission.

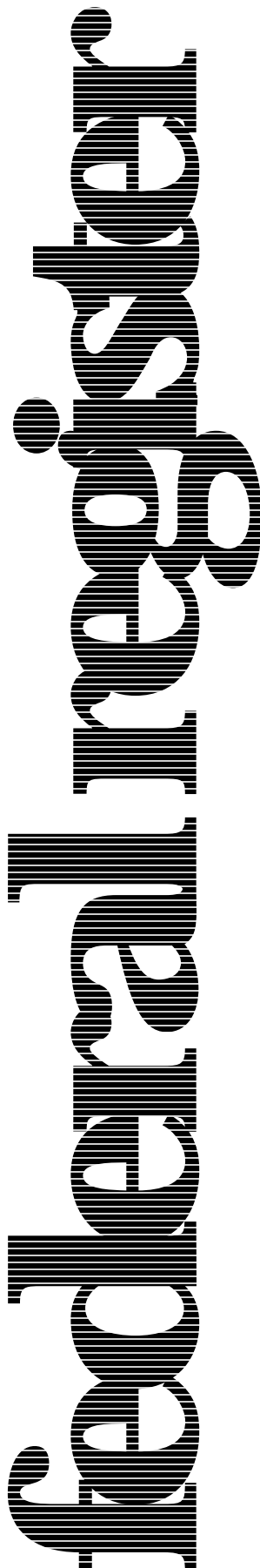
ACTION: Final rule.

SUMMARY: Action in this document allots Channel 255A to Walhalla, Michigan, in response to a petition filed by Roger Lewis Hoppe II. See 12 FCC Rcd 4127 (1997). There is a site restriction 6.3 kilometers southwest of the community. Canadian concurrence has been obtained for the allotment of Channel 255A at Walhalla at coordinates 43-54-08 and 86-10-13. A one-step application filed by Bay View Broadcasting, Inc. requesting the substitution of Channel 274A for Channel 276A at Pentwater, Michigan, has been considered as a counterproposal in this proceeding (BPH-970319IE). The allotment of Channel 255A at Walhalla instead of Channel 274A removes the conflict with the pending application at Pentwater. With this action, this proceeding is terminated. A filing window for Channel 255A at Walhalla, Michigan, will not be opened at this time. Instead, the issue of opening a filing window for this channel will be addressed by the Commission in a subsequent order.

EFFECTIVE DATE: May 18, 1998.

FOR FURTHER INFORMATION CONTACT: Kathleen Scheuerle, Mass Media Bureau, (202) 418-2180.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's Report and Order, MM Docket No. 97-118, adopted March 25, 1998, and released April 3, 1998. The full text of this Commission decision is available for inspection and copying during normal business hours in the Commission's Reference Center (Room 239), 1919 M Street, NW, Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractors, International Transcription Services, Inc., 1231 20th Street, NW., Washington, DC. 20036, (202) 857-3800; facsimile (202) 857-3805.



Friday
October 24, 1997

Part II

Environmental Protection Agency

40 CFR Part 9, et al.

**Acid Rain Program: Revisions to Permits,
Allowance System, Sulfur Dioxide Opt-
Ins, Continuous Emission Monitoring,
Excess Emissions, and Appeal
Procedures; Final Rule**

ENVIRONMENTAL PROTECTION AGENCY**40 CFR Parts 9, 72, 73, 74, 75, 77, and 78****[FRL-5908-5]****RIN 2060-AF43****Acid Rain Program: Revisions to Permits, Allowance System, Sulfur Dioxide Opt-Ins, Continuous Emission Monitoring, Excess Emissions, and Appeal Procedures****AGENCY:** Environmental Protection Agency (EPA).**ACTION:** Final rule.

SUMMARY: Title IV of the Clean Air Act (the Act) authorizes the Environmental Protection Agency (EPA or Agency) to establish the Acid Rain Program. The purpose of the Acid Rain Program is to significantly reduce emissions of sulfur dioxide and nitrogen oxides from utility electric generating plants in order to reduce the adverse health and ecological impacts of acidic deposition (or acid rain) resulting from such emissions. On January 11 and March 23, 1993, the Agency promulgated final rules governing permitting, the allowance system, continuous emissions monitoring, excess emissions, and appeal procedures. On December 27, 1996, the Agency published proposed revisions to those rules, most of which revisions are addressed in today's final rule.

After considering its experience in applying the Acid Rain Program rules since 1993, the Agency believes that the permitting, excess emissions, and appeal procedures rules (as well as minor aspects of the monitoring rule) can be streamlined and improved in order to reduce the burden on utilities, State and local permitting authorities, and EPA. Today's final rule revisions streamline the Acid Rain Program while still ensuring achievement of its statutory goals of reducing sulfur dioxide and nitrogen oxides emissions.

In addition, EPA is revising the sulfur dioxide allowances for one unit. Each allowance authorizes the emission of one ton of sulfur dioxide. Under the Acid Rain Program, utility units (i.e., fossil fuel-fired boilers or turbines) are allocated annual allowances and must not emit sulfur dioxide in excess of the amount authorized by the allowances that they hold. Today's final rule revises one unit's allowances pursuant to a settlement agreement. In a future final action, EPA will act on the other allowance revisions that were set forth in the December 27, 1996 proposed rule.

EFFECTIVE DATE: November 24, 1997.

ADDRESSES: Docket No. A-95-56, containing the information used to develop the final rule, is available for public inspection and copying from 8:30 a.m. to 12 p.m. and 1 p.m. to 3:30 p.m., Monday through Friday, excluding federal holidays, at EPA's Air Docket Section (6102), Waterside Mall, Room M1500, 1st Floor, 401 M Street, SW, Washington, DC 20460. Additional information concerning the original rules and today's final revisions is found in Docket Nos. A-90-38 (permits), A-91-43 and A-92-06 (allowances), A-90-51 (continuous emissions monitoring), A-91-68 (excess emissions), A-91-69 (general), and A-93-15 (appeals). A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT:

Dwight C. Alpern, Attorney-advisor, at (202) 233-9151 (U.S. Environmental Protection Agency, 401 M Street, SW, Acid Rain Division (6204J), Washington, DC 20460); or the Acid Rain Hotline at (202) 233-9620.

SUPPLEMENTARY INFORMATION:**Regulated Entities**

Entities potentially regulated by this action are fossil-fuel fired boilers or turbines that serve generators producing electricity for sale. Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Electric service providers.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria in § 72.6 and the exemptions in §§ 72.7, 72.8, and 72.14 of title 40 of the Code of Federal Regulations. If you have questions regarding the applicability of this action to a particular entity, consult the persons listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Organization. The information in this preamble is organized as follows:

I. General**II. Part 72: Applicability of and Exemptions From Acid Rain Program****A. Applicability****B. Exemptions****1. New Units Exemption****2. Retired Units Exemption**

3. Industrial Utility-Units Exemption
- III. Part 72: Interaction of Acid Rain Permitting and Title V
 - A. Relationship Between Acid Rain Rules and Parts 70 and 71
 - B. State Authority to Administer and Enforce Acid Rain Permits
 - C. Required Elements for State Acid Rain Program
- IV. Part 72: Miscellaneous Permitting Matters
 - A. Definitions
 - B. Designated Representative
 - C. Compliance Plans
 - D. Federal Permit Issuance
 - E. Permit Revision
 - F. Reduced Utilization Accounting
- V. Part 73: Allowances
 - A. Allowance Tables
 - B. Small Diesel Refinery Provisions
- VI. Part 75: Monitoring of Units Burning Digester or Landfill Gas
- VII. Part 77: Excess Emissions
- VIII. Part 78: Administrative Appeals
- IX. Administrative Requirements
 - A. Executive Order 12866
 - B. Unfunded Mandates Act
 - C. Paperwork Reduction Act
 - D. Regulatory Flexibility
 - E. Submission to Congress and the General Accounting Office
 - F. Miscellaneous

I. General

A significant number of the revisions in the December 27, 1996 proposal did not receive any comment. Most of the proposed revisions, including all on which comment was received, are discussed in this preamble. Unless otherwise stated below, revisions are adopted in today's final rule for the reasons discussed in the proposal.

II. Part 72: Applicability of and Exemptions From Acid Rain Program**A. Applicability**

The proposal included two types of revisions of the existing rule. First, the definition of "power purchase commitment" was revised to extend to three years the period by which a letter of intent must have resulted in execution of a power sales agreement. Second, minor revisions were made to the procedure for petitioning for a determination by the Administrator on the applicability of the Acid Rain Program to a unit. Supportive comment was received on the first revisions, and no comment was received on the second. The revisions are therefore adopted in today's rule.

B. Exemptions**1. New Units Exemption**

Section 72.7 of the existing rule provides an exemption from most Acid Rain Program requirements for new units that serve generators with a total capacity of 25 MWe or less and that combust clean fuels. The proposal made

several types of revisions in order to streamline the new units exemption. With the changes discussed below,¹ revisions are adopted in today's rule for the reasons discussed here and in the proposal.

First, the requirement for the combustion of clean fuels at the unit was revised in the proposal. While the existing rule requires that only fuel with a sulfur content 0.05 percent or less by weight be combusted, the proposal stated that the unit must burn gaseous fuel with an annual average sulfur content of 0.05 percent or less by weight and nongaseous fuel with an annual average sulfur content of 0.05 percent or less by weight. Commenters supported the revisions and explained that the existing rule was unduly restrictive. These revisions are adopted in today's rule.

The proposal also set forth revised procedures for determining annual average sulfur content by weight for gaseous and nongaseous fuel. The proposal eliminated provisions mandating the use of listed methods for measuring sulfur content but included provisions concerning the required frequency of sampling. The proposal provided explicitly that the owners and operators of the unit bear the burden of proving compliance with the sulfur content requirement. Commenters supported these revisions but suggested that EPA state that any "recognized industry standard such as an ASTM method would be acceptable." Commenters also urged that the rule state that a unit that burns only diesel fuel meeting the requirements of diesel fuel for motor vehicles be assumed to meet the limits on sulfur content of fuel.

The proposed revisions are adopted in today's rule. Under the final rule, since methods for measuring sulfur content are not specified, the Agency will evaluate on a case-by-case basis the information provided by the owners and operators of a unit on sulfur content. In order to ensure that owners and

operators understand that they must use a reasonable method to determine sulfur content, the final rule adopts language from section 412 concerning emission monitoring and states that the method of determining sulfur content must provide information that is reasonably precise, reliable, accessible, and timely. EPA anticipates that owners and operators will meet their burden of proof by using a method that is generally recognized in the industry (such as the applicable ASTM method set forth in the existing rule), is applicable to the unit, and is consistent with the other provisions (e.g., sampling frequency requirements) of today's rule.

Further, EPA recognizes that diesel fuel for motor vehicles is required under § 80.29 to have a sulfur content of 0.05% by weight. Commenters have suggested that such diesel fuel should be assumed to meet the sulfur content limit without any testing. One commenter stated that the testing by the unit owner was burdensome and duplicative of testing by the fuel supplier.

However, not all diesel fuel is required to meet the sulfur content limit; only diesel fuel for use in motor vehicles must meet the limit under § 80.29. 40 CFR 80.29(a)(1)(i). A significant amount of diesel fuel is produced for other uses (e.g., as fuel for electric generation by utilities) has a higher sulfur content than mandated for diesel fuel for motor vehicles. *Petroleum Supply Annual 1996*, Vol. 1 at 51, Table 17 (Energy Information Administration, June 1997) (indicating that about 37% of 1996 U.S. distillate production (which is primarily diesel fuel as defined in § 72.2) had a sulfur content above 0.05% by weight).² Moreover, the higher-sulfur diesel fuel is used by many utility units that combust diesel fuel. For example, during 1996 and the first half of 1997, diesel fuel with a sulfur content of 0.05% or less by weight accounted for only about 13% of the total heat input for affected units that used diesel fuel and were required to report the sulfur content of their fuel to EPA. Most of the diesel fuel used had a much higher sulfur content; diesel fuel with more than twice the sulfur content (i.e., over 0.10% sulfur by weight) accounted for about 81% of such total heat input.³

In contrast, virtually all commercially available natural gas in the U.S. has sulfur content at or below 0.05% by weight. Because of the toxic effects of

hydrogen sulfide and its corrosive effect on pipeline and customer equipment, pipelines generally provide pipeline transportation or distribution service only for natural gas with a very low hydrogen sulfide content (e.g., 0.25 to 0.30 grain per 100 standard cubic feet), which results in total sulfur content far below 0.05% by weight. See, e.g., H. Dale Beggs, *Gas Production Operations* at 204-5, 209-11, and 227 (1984); and 49 CFR 192.475(c) (provision, in U.S. Department of Transportation minimum safety standards for natural gas pipelines, limiting the hydrogen sulfide content of gas "stored in pipe-type or bottle-type holders" to 0.25 grain per 100 standard cubic feet).

Since diesel fuel is widely available that does not meet the sulfur content limit, diesel fuel must be treated like any other fuel that is combusted at an exempt new unit and that could potentially exceed the limit. The owners and operators of the unit combusting the fuel must demonstrate that the limit is being met using the results of reliable testing methods consistent with the sampling and other requirements of today's rule. Of course, under today's rule, the owners and operators are not required to conduct the testing themselves. EPA will consider testing by fuel suppliers in determining whether the owners and operators have met their burden of proof.

Second, the proposal streamlined the procedure for obtaining a new units exemption and reduced the burden imposed by the procedure on owners and operators and permitting authorities. The existing rule required owners and operators of a unit to submit an application and for permitting authorities to provide notice and opportunity for comment before issuing an exemption. The proposal made the obtaining of an exemption largely automatic so long as the capacity, annual fuel use, and recordkeeping requirements are met. Under the proposal, owners and operators of a unit meeting these requirements must submit a statement to the permitting authority (and, if EPA is not the permitting authority, to EPA) that the unit meets, and will continue to meet, the requirements for the exemption. The proposal states that a new units exemption is effective on January 1 of the first full calendar year for which the unit meets the exemption requirements and that the statement must be submitted by December 31 of such year. In short, where the end-of-year submission deadline and other requirements for an exemption are met, the exemption will cover the entire year in which the submission was made. The

¹ In addition, today's rule adds language clarifying that the requirement that a unit serve one or more generators with total nameplate capacity of 25 MWe or less during the period of the exemption does not apply to the time before the unit commenced commercial operation. Today's rule also adds language, under "Special Provisions", to reiterate the fact (reflected in § 72.7(a)) that an exempt unit must continue to meet the requirements (e.g., the sulfur content limits for its fuels) throughout the duration of the exemption. Another addition in today's rule is language clarifying that when the exemption is lost, the unit must comply with Acid Rain permitting and monitoring requirements, starting after the loss of the exemption (e.g., starting on the first date on which the unit is no longer exempt). Similar language is added to the retired units and industrial utility-units exemption provisions.

² Relatively little distillate fuel oil is imported into the U.S., and most of it has a sulfur content exceeding 0.05%. *Id.* at 55, Table 20.

³ Report to Docket: Diesel Fuel Use of Units Required to Use Fuel Sampling Under part 75, appendix D (September 16, 1997).

proposed revisions are adopted in today's rule.

The proposal established some additional procedures for the relatively few new units that were allocated allowances.⁴ The owners and operators of such units must submit a statement (similar to the one for units without allocations) stating that the owners and operators are surrendering the allowances, and proceeds from the auction of allowances, starting with the first year for which the unit is exempt. Under the proposal, the exemption for a unit allocated allowances is effective on January 1 of the first year for which the Administrator actually deducts the full allowance allocation and actually receives the full amount of auction proceeds. Commenters contended that this "unfairly" makes the exemption contingent on an event (i.e., the deduction of allowances) beyond the control of the owners and operators. Allegedly, the exemption should be contingent only on submission of the statement surrendering allowances and proceeds.

EPA notes that the only issue is the date on which the exemption becomes final. Once the Administrator actually makes the necessary allowance deductions and receives the proceeds, the exemption runs starting from January 1 of the year for which the unit meets the requirements (e.g., fuel sulfur limits and allowance and proceeds surrender) for this exemption. The difficulty with making the exemption effective when the surrender statement is submitted is that there is no guarantee that the unit's allowance account actually has sufficient allowances to deduct or that the proceeds are actually available to and received by the Administrator.

In order to ensure that the actual deduction of allowances in the unit's Allowance Tracking System account is not unduly delayed, the final rule requires that, within 5 business days of receiving the owners' and operators' surrender statement, the Administrator either makes the allowance deductions or notifies the owners and operators that there are insufficient allowances for the deductions. This is the same period of time in which, under §§ 73.52 and 73.53, the Administrator must act on an allowance transfer request. The

approach adopted in today's rule accommodates both the concern that the necessary number of allowances actually be available for deduction before the exemption is effective and the concern that the effectiveness of the exemption not be unnecessarily delayed.

Finally, the proposal provided that a unit with a new units exemption is not an "affected unit" and so does not need an operating permit under part 70 or 71 unless such a permit is required because non-title IV, federal requirements applicable to the unit. See 61 FR 68343. However, for the case where, because of non-title IV requirements, the source at which the unit is located has or must have an operating permit, the proposal did not exclude the new units exemption from the general requirement to incorporate applicable federal requirements in the operating permit. See 42 U.S.C. 7661a(b)(5)(A) and 7661c(a). The final rule adopts the proposed provision and makes it clear that if, because of non-title IV requirements, an operating permit is issued to the source, the new units exemption must be reflected in that operating permit. In particular, after the actions necessary for the new units exemption to take effect have been completed (e.g., the receipt by the permitting authority of a statement of exemption by the owners and operators of the unit and the notification by the Administrator that he or she has deducted any allowances, and received any allowance proceeds, required to be surrendered), the permitting authority must add the provisions and ongoing requirements of the exemption to any operating permit that covers the source at which the unit is located. Consistent with the elimination of the requirement for notice and comment on a new unit's exemption, the addition of the exemption to the permit is an administrative amendment. A written new units exemption issued under the existing rule prior to revision by today's rule must similarly be added to any operating permit.

Under this approach, the exemption alone will not result in issuance of an operating permit, but, if an operating permit would be issued for the source in any event, that operating permit will include the ongoing requirements imposed on the unit under the exemption. This approach reasonably implements the concept that an operating permit should include the applicable federal requirements for a source. For the same reasons, analogous provisions are included in today's rule with regard to the retired units

exemption and the industrial-utility units exemption.

2. Retired Units Exemption

Section 72.8 of the existing rule provides an exemption from Acid Rain Program requirements for retired units. The proposal made several types of revisions in order to streamline this retired units exemption. First, while the existing rule required owners and operators of a unit to submit an application for the exemption and for permitting authorities to provide public notice and opportunity for comment before issuing a final exemption, the proposal made the obtaining of an exemption largely automatic so long as the unit is permanently retired. Second, the proposal clarified that the exemption applies to most Acid Rain Program requirements.

No comments were received on these proposed revisions. In order to make it clear that only Phase I or Phase II units, and not opt-in units under part 74, are eligible for the retired units exemption, today's rule states that the exemption applies to "any affected unit (except for an opt-in source)". This exclusion of opt-in sources is consistent with the existing provisions of part 74 that impose separate requirements with regard to permanent shutdown of opt-in sources. See, e.g., 40 CFR 74.46. In addition, to provide flexibility where a retired unit has no allowance allocations and has not selected a designated representative, the final rule allows a certifying official to submit notice of the exemption to the permitting authority. For the reasons discussed here and in the proposal, the revisions, as modified, are adopted in today's rule.

3. Industrial Utility-Units Exemption

Scope of Exemption. In the proposal EPA established a new exemption for certain industrial units that generate only incidental amounts of electricity for sale. As explained in detail in the preamble of the proposal, "utility units" (the entities subject to the Acid Rain SO₂ emission limitation and other requirements of the Acid Rain Program) include, with certain exceptions, any unit serving a generator that produced electricity for sale any time starting in 1985. With certain exceptions (e.g., for cogenerators), an industrial unit serving a generator that produced any amount of electricity for sale (referred to hereinafter as simply an "industrial utility-unit")⁵ is an affected unit under

⁴ While the proposal referred to allowances allocated under Table 2 or 3 of subpart B of part 73, today's rule simply refers to allowances allocated under that subpart. Under part 73 as currently organized, all allocations to new units are included in the tables. Since in the future EPA may reorganize the allowance allocation information that is currently presented in two separate tables, today's rule adopts a more general reference to new-unit allowance allocations.

⁵ The proposal referred to these units as simply "industrial units". In order to minimize confusion between these units and industrial boilers not used

the Acid Rain Program regardless of the amount of the sale relative to the total generation by the generator and whether or not the sale is to the general public or to a public utility for resale to the public. Moreover, the requirement to hold allowances to cover SO₂ emissions and to meet any applicable NO_x emission limitation under the Acid Rain Program applies to all emissions from the unit, not simply the portion that might be attributed to generation of the electricity sold.

Despite the applicability of the requirement to hold allowances, EPA has not allocated allowances to industrial utility-units that might have qualified for allowance allocations under section 405 of the Act, including some units whose owners submitted timely comments relating to allowance allocations. On March 23, 1993, EPA issued notices stating that such industrial utility-units would not be included in the National Allowance Database, on which allowance allocations are based, because EPA "believe[d]" that the units were not affected units. 58 FR 15720, 15727 (1993). On the same date, EPA also issued a final allowance allocation list that allocated allowances only to units then "believed" to be affected units. 58 FR 15634, 15641 (1993). EPA stated that no allowances would be allocated to units that were subsequently determined to be, or that subsequently became, affected units. *Id.*

In light of these circumstances, EPA proposed a limited exemption from the Acid Rain Program for industrial utility-units that served, any time starting in 1985, a generator that produced electricity for sale. First, the industrial utility-unit must have no owner or operator of which the principal business is electricity sale, transmission, or distribution or that is a public utility subject to State or local utility regulation.⁶ Such unit must not be a cogeneration unit since cogeneration units already are covered by an express exemption in the title IV. Further, on or before March 23, 1993, the owners or operators of the unit must have entered into an interconnection agreement (and any related power purchase agreement)

with a public utility requiring that the generator served by the unit produce electricity for sale only for incidental sales of electricity to that public utility. Moreover, in 1985 and any year thereafter, the generator served by the unit must have actually produced only incidental electricity sales for the utility, as required under the interconnection agreement and any related power purchase agreement. Incidental sales were defined as sales not exceeding the lesser of 10 percent of the generating output capacity of the generator or 10 percent of the actual annual electric output of the generator.

The proposal established a petition and notice-and-comment procedure for owners or operators to apply for the exemption and for the Agency to review and approve or disapprove the exemption. If, after approval of the exemption, any of the conditions for obtaining the exemption are no longer met, the exemption terminates automatically. The proposal, as changed below, is adopted for the reasons discussed here and in the proposal.⁷

All parties commenting on the new industrial utility-units exemption supported the concept of such an exemption. However, these commenters objected to various, specific provisions. First, commenters claimed that EPA should "totally" exempt industrial utility-units without regard to the amount of electricity sold by an industrial utility-unit and/or without regard to whether the unit was contractually obligated to sell electricity on or before March 23, 1993. Allegedly, industrial utility-units not qualifying for the exemption will incur significant costs "not related" to the objectives of title IV. It was argued that if industrial utility-units that cannot meet the criteria of the rule are not exempt, "agreements" providing for sales by industrial utility-units to utilities may be "discontinued", forcing utilities to "look elsewhere for their emergency and backup power needs." It was also argued that the costs of complying with the Acid Rain Program "will exceed the benefits of the limited reductions to be

achieved by the regulations" since the estimated amount of SO₂ emissions is small relative to the annual 8.95 million ton cap for utility units. Since industrial utility-units are allegedly subject to the nationwide cap of 5.60 million tons on total annual SO₂ emissions by "industrial sources", regulation of industrial utility-units under the existing Acid Rain regulations was claimed to be unnecessary.

However, EPA begins with the fact, undisputed by any commenter, that Congress included non-cogeneration industrial utility-units in the Acid Rain Program and thus under the annual 8.95 million ton cap for SO₂ emissions and under applicable NO_x emission limitations. See 61 FR 68344. Further, although the preamble of the proposal stated that industrial utility-units are also under the 5.60 million ton cap for "industrial sources" under section 406(b) of the Clean Air Act Amendments of 1990, EPA now believes, on further consideration, that industrial utility-units (which served, any time starting in 1985, a generator that produced electricity for sale) are not covered by the latter cap.

Section 406(b) of the Clean Air Act Amendments of 1990 states that if SO₂ emissions from "industrial sources * * * may reasonably be expected to reach levels greater than 5.60 million tons per year," the Administrator may take actions "to ensure that such emission do not exceed" the cap. 42 U.S.C. 7651 note. From section 406(a), it is clear that the definition of "industrial source" in section 402 of the Clean Air Act applies. Under section 402, an "industrial source" is: a unit that does not serve a generator that produces electricity, a "nonutility unit" as defined in this section, or a process source as defined in section 410(e). 42 U.S.C. 7651a(24)

As discussed above, an industrial utility-unit is a unit that is not owned or operated by a utility but that served, anytime starting in 1985, a generator that produced electricity for sale and therefore is a utility unit under section 402(17). Such a unit does not fall within any of the three groups of units that are defined as "industrial sources".⁸ Consequently, the units that are under consideration in this rulemaking for

in generation of electricity for sale, and because generation of electricity for sale makes industrial units "utility units" under title IV, the final rule refers to the units as "industrial utility-units".

⁶In order to prevent the requirement from being circumvented through the position of the owner or operator in the corporate structure, the proposal stated that no owner or operator, subsidiary or affiliate or parent company of the owner or operator, or combination thereof could have such a principal business. Consistent with this approach, the final rule also applies this to any division of the owner or operator.

⁷In the proposal, EPA relied on the *Report For Docket: Industrial Units* (October 31, 1996). In the report, EPA estimated the number of industrial utility-units in the U.S. that may qualify for an industrial utility-units exemption under § 72.14 and their total annual SO₂ and NO_x emissions. One commenter asserted that the report overestimated the emissions for two units owned by the commenter. Assuming the accuracy of the commenter's emission estimates, the total annual SO₂ and NO_x emissions estimates for industrial utility-units are reduced by about 10%, i.e., to about 41,000 tons of SO₂ and 17,000 tons of NO_x. This is not a significant change and does not affect EPA's determinations concerning the industrial utility-units exemption.

⁸Section 406(a) also states that "industrial sources" include units subject to section 405(g)(6), i.e., certain qualifying facilities and independent power production facilities that are exempt from title IV. The reference in section 406(b) to units "subject to section 405(g)(5)" is an inadvertent error that should be read as citing section 405(g)(6). See *National Annual Industrial Sulfur Dioxide Emission Trends 1995-2015*, EPA-454-R-95-001, at ES-2 (EPA 1995). Industrial utility-units are not exempt under section 405(g)(6).

inclusion in the industrial utility-units exemption are not covered by the 5.60 million ton cap. Contrary to commenters, the Clean Air Act Amendments of 1990 do not give EPA the "option" of regulating industrial utility-units under section 406. In contrast, Congress exempted certain cogeneration facilities from the Acid Rain Program (e.g., the 8.95-million-ton cap) and included them in the 5.60-million-ton cap. Under section 402(17)(C) and (25), exempt cogeneration facilities are excluded from the definition of "utility unit" and so are "nonutility" units covered by the "industrial source" cap.

This reinforces the conclusion that industrial utility-units are intended to be covered by the Acid Rain Program and leads to the conclusion that a blanket exemption for all industrial utility-units is inconsistent with the overall regulatory scheme under title IV.⁹ Exempting all industrial utility-units, without regard to the amount of their electricity sales or to when the sales became contractually obligated, would result in a potentially increasing group of existing and future units that would generate electricity for sale but would be outside both the utility unit and the "industrial source" caps. Particularly since the ongoing changes in the structure of the electric industry make it difficult to predict how many industrial utility-units there may be in the future and how they may be used, EPA rejects such an open-ended exemption from both caps.¹⁰ Moreover, commenters supporting a blanket exemption ignore the fact that the Acid Rain Program is aimed at reducing both SO₂ emissions and NO_x emissions. To the extent that existing coal-fired industrial utility-units are Group 1 (i.e., dry bottom wall-fired or tangentially fired) or Group 2 (i.e., cell burner, cyclone, wet bottom, or vertically fired) boilers, exempting them removes the applicability of the Group 1 or Group 2 NO_x emission limits, which in some cases may be the only NO_x limits for these boilers under the Act.

⁹ EPA rejects as speculative and irrelevant the commenter's suggestion that title IV may be amended in a way that would require non-exempt industrial utility-units to make additional, "prohibitively expensive" reductions.

¹⁰ Even if the "total" exemption were limited to the specific possible industrial utility-units identified thus far by EPA (see *Report to Docket: Industrial Units* (October 31, 1996)), the amount of generation and emissions covered by a "total" exemption could increase in the future. Moreover, the commenters suggested no basis for limiting a "total" exemption to those tentatively identified industrial utility-units if other units are subsequently found to meet the "total"-exemption criteria.

EPA also rejects, as unsupported and speculative, the claim that subjecting industrial utility-units to Acid Rain Program requirements will make interconnection agreements and related power sales agreements between such units and utilities economically prohibitive. EPA agrees that industrial companies may have more difficulty than utilities (at least under the current scheme of utility rate regulation) in passing through the costs of the Acid Rain Program. However, that is a far cry from concluding that electricity sales by existing industrial utility-units would cease or that no new industrial utility-units would contract to make such sales.

EPA therefore maintains that, if there is to be any exemption for industrial utility-units, the exemption must be strictly limited in order to resolve the specific problem set forth in the preamble of the proposal. That problem is that some industrial utility-units have only incidental activities (i.e., electricity sales) bringing the entire operation of the unit under the Acid Rain Program and that these units likely qualified for, but were not allocated, allowances. Strictly limiting the exemption to address this problem will minimize the potential environmental impact of this resolution on SO₂ and NO_x emissions and will better harmonize the exemption with the basic regulatory scheme under title IV. In fact, without the specific limits on the exemption set forth in today's rule based on the magnitude of electricity sales and the time period when electricity sales first became contractually required, EPA would reconsider whether any exemption for industrial utility-units should be established.

As an alternative to a blanket exemption for industrial utility-units, one commenter suggested modifying the definition of "incidental sales of electricity" so that units selling up to one-third (rather than up to 10 percent, as under the proposal) of their electric generation to utilities could qualify as exempt industrial utility-units. Allegedly, limiting sales to up to one-third of annual electric generation would be consistent with the statutory exemption for cogeneration facilities. Under section 402(17)(C) and § 72.6(b)(4), a cogeneration facility that supplies to a utility, on an annual basis, an amount of electricity not exceeding one-third of its potential electrical output capacity or 219,000 MWe-hrs is an unaffected unit and is not subject to the Acid Rain Program. The commenter supported limiting industrial utility-units to annual electricity sales equal to the lesser of one-third of capacity or one-third of actual generation.

Reflecting that the rationales for the industrial utility-units exemption and the statutory cogeneration facility exemption are not identical, today's rule does not make the requirements for the two types of exemptions identical. On one hand, the cogeneration facility exemption reflects Congressional intent, manifest in section 402(17)(C) of the Act, that certain cogeneration facilities be entirely exempt from the Acid Rain Program whether or not they had contracted before enactment of title IV to provide electricity at a fixed price. Presumably, this is because, by using the same steam both for electric generation and industrial purposes, cogeneration facilities are inherently more efficient than other units that generate electricity. See 40 CFR 72.2 (defining "cogeneration unit" as unit producing electricity and useful thermal energy "through sequential use of energy"). On the other hand, the industrial utility-units exemption addresses the category of industrial utility-units, which were intended by Congress to be subject to the Acid Rain Program but, with regard to certain individual units, were not allocated allowances for which they likely qualified. They lack the sequential use of energy that makes cogeneration facilities inherently more efficient. As discussed above, EPA maintains that the industrial utility-units exemption should, under these circumstances, be more narrowly drawn than the provisions for exempting cogeneration facilities. Consequently, EPA disagrees with the approach of using the limit on electricity sales by exempt cogeneration facilities in setting the limit on electricity sales by exempt industrial utility-units.

In the proposal, the industrial utility-units exemption is limited to units that were contractually obligated as of March 23, 1993 to make only incidental sales of electricity to utilities. The proposal defines "incidental sales" as sales not exceeding 10 percent of either nameplate capacity or total actual generation because that level seemed to be consistent with the general level of historical electricity sales by the type of unit intended to be covered by the exemption. This approach limits the exemption by restricting both the number of units covered by the exemption and the amount of electricity sales to historical levels and does not allow expansion beyond those levels. None of the commenting owners of units potentially qualifying for the industrial utility-units exemption claimed that they had actually made, in any past year, electricity sales in excess

of the 10 percent limit or that the 10 percent limit is unrepresentative of historical levels. EPA maintains that it is appropriate to impose on the industrial utility-units exemption a limit reflecting historical levels and that, on their face, electricity sales as high as one-third of total generation cannot be regarded as simply incidental to the operation of the unit involved. For these reasons, while choosing a 10-percent level as the cutoff point for "incidental sales"—like choosing any specific cutoff point—is to some extent arbitrary, EPA maintains that the chosen level is reasonable. Today's rule, like the proposal, defines "incidental electricity sales" as an amount of electricity sales that does not exceed the smaller of 10 percent of the nameplate capacity of the generator served by the unit times 8,760 hours per year or 10 percent of the actual annual electric output of that generator.

Today's rule also continues to impose the incidental-electricity-sales limit on sales starting in 1985 and continues to require that the contractual obligation to make such sales must have been in place on March 23, 1993. One commenter objected to having "two different deadlines" and argued that only sales starting in 1993 should have to meet the incidental-electricity-sales limit. EPA rejects this approach.

Under the industrial utility-units exemption, EPA considers the electricity sales of the unit starting in 1985 because that is analogous to the approach taken by Congress in section 402(17) in determining what units are utility units that are subject to the Acid Rain Program. With certain exceptions, any unit that at any time starting in 1985 or thereafter serves a generator that produces electricity for sale is a "utility unit" subject to the Acid Rain Program. 42 U.S.C. 7651a(17)(A). In crafting the industrial utility-units exemption, EPA reasonably takes a parallel approach of considering actual sales starting in 1985. Actual sales before 1985 will not be considered. EPA sees no basis for the commenter's suggestion of ignoring any non-incidental electricity sales from 1985 to 1993. In essence, EPA is requiring that, in order to be exempt, a unit must have maintained its character as an industrial utility-unit making only incidental sales throughout the period generally used to determine applicability of the Acid Rain Program.

The rationale for the "second deadline" in the industrial utility-units exemption—i.e., the requirement that there be, as of March 23, 1993, a contractual obligation to make incidental electricity sales—is set forth in detail in the proposal and is adopted

here. 61 FR 68346. This requirement also makes it likely that the unit was either (i) in commercial operation as of November 15, 1990 or (ii) was under construction by December 31, 1990 and therefore qualified for, but was not allocated, allowances in Phase II. See 42 U.S.C. 7651d(a)–(f) and (h)–(i) (allowances for existing units) and (g) (allowances for units under construction and operating by specified deadlines).

Termination of exemption. Under the proposal, a unit's industrial utility-units exemption terminates automatically once any of the original requirements for granting the exemption are no longer met. Commenters raised concern that the proposal terminates the exemption if the contractual agreement that requires incidental electricity sales by the unit, and on which the granting of the exemption was originally based, expires or is amended. A particular agreement may have a termination date even though the parties intend for the relationship to continue. Further, an agreement may be modified directly or through replacement by a new agreement, e.g., in order to change the names of the parties or the electricity prices. According to commenters, the exemption should not be terminated so long as there is not an obligation to sell more than an incidental amount of electricity.

EPA understands the concern that replacement of the interconnection agreement on which an exemption is based (or of the power purchase agreement related to the interconnection agreement) by a follow-on agreement that continues to require the same amount of electricity sales should not result in termination of the exemption. EPA also recognizes a similar concern with regard to amendment of the interconnection agreement or power purchase agreement. On one hand, the rule should provide for some flexibility allowing agreements to be modified or replaced so long as the underlying electricity sales obligation of the industrial utility-unit is not altered in a way that undermines the original basis for the unit's exemption. On the other hand, EPA is concerned that this flexibility should not have the effect of allowing expansion of the unit's exemption beyond its original scope. For example, just as a unit that as of March 23, 1993 did not serve a generator required to produce electricity for sale and that begins after that date to be involved in electricity sales is not exempt, an exempt unit should not be able to expand its involvement in electricity sales after March 23, 1993 and retain the exemption. Finally, EPA believes it must consider that future

modifications or replacements of agreements will be taking place in the context of restructuring of the electric industry, where utilities may be restructured and renamed.

In order to meet all of these concerns, today's rule provides that, in applying the automatic-termination provisions of the exemption, the interconnection agreement (and related power purchase agreement) and any successor agreement will be considered. For example, the proposal stated that if the interconnection agreement on which the exemption is based expires or terminates and the generator served by the unit continues to produce electricity for sale, the exemption for the unit terminates. Under today's rule, if that interconnection agreement is replaced or supplemented by a "successor agreement", the expiration or termination of the original agreement will not cause termination of the exemption. Today's rule defines "successor agreement" in a way that is aimed, on one hand, at requiring the unit to continue to meet the basic requirements for the exemption and taking account of future electric industry restructuring and, on the other hand, at preventing this flexibility from being used to expand beyond the original scope of the exemption when it was approved.

A "successor agreement" is defined as an agreement that modifies, replaces, or supersedes the interconnection agreement or related power purchase agreement on which the exemption was originally based. Further, a "successor agreement" must be between owners and operators of the unit and another party (which may be the same party as in the original agreement) that (i) is principally in the electric utility business or is a public utility subject to State or local jurisdiction and (ii) is obligated to sell electricity to the owners and operators of the unit. In addition, the "successor agreement" must require the generator served by the unit to produce electricity for sale only for incidental electricity sales to that party. Finally, the total amount of electricity that the generator served by the unit is required to produce for sale under all such contracts that are in effect (i.e., the interconnection agreement, related power purchase agreement, and any successor agreement) must not exceed the amount that such generator was required to produce for sale under the original interconnection agreement and related power purchase agreement on which the exemption was initially based.

Procedural and other issues. Under the proposal, a unit seeking an

industrial utility-units exemption must submit a petition to the local permitting authority. The processing of the petition is similar to that for an Acid Rain permit. However, once an exemption is approved, it has no uniform, fixed term and continues in effect unless and until it is automatically terminated. Commenters claimed that the process of petitioning for the exemption would be burdensome. They noted that the proposal removed the requirements to apply for the new units or retired units exemption and argued that the industrial utility-units exemption should similarly be made "self-executing".

When the new units and retired units exemptions were first adopted by rule, the regulations required submission of petitions for the exemptions, processing by the permitting authority using the permit notice-and-comment procedures, and renewal every five years. The December 27, 1996 proposal and today's rule make those exemptions self-executing for the most part. With some exceptions, owners and operators of units meeting the fairly straightforward requirements of the new units or retired units exemptions need only notify the permitting authority and EPA of their qualification for the exemption.

In the case of the industrial utility-units exemption, EPA has decided that it is necessary to require the submission of a petition and processing by the permitting authority. This is a newly established exemption, with which the Agency has had no experience. Moreover, in determining whether to establish the exemption, EPA has found it difficult to obtain information on which units might qualify. *See Report to Docket: Industrial Units* (October 31, 1996). In addition, determination of whether a unit qualifies for the exemption is not as straightforward as the determination of qualification for the new units or retired units exemption. Qualification for an industrial utility-units exemption depends, in part, on interpretation of interconnection and power purchase agreements. Further, particularly in light of other provisions of today's rule that streamline the permit processing procedures and thus also apply to processing of a petition for industrial utility-units exemption, EPA maintains that the petition and review requirements for the exemption are not unduly burdensome on either the unit owners and operators or the permitting authorities. Today's rule requires a one-time review process in that once approved, the exemption continues in effect without the need for renewal.

One final issue raised by a commenter (Zinc Corporation of America) is whether industrial utility-units that do not qualify for an industrial utility-units exemption should be allocated allowances. Allegedly, such units qualify for allowances but were not allocated any due to EPA's "oversight in allowance allocation".

The difficulty with this argument is that it ignores the fact that EPA has previously specified deadlines by which parties claiming that an erroneous failure to allocate allowances to a unit were required to submit such claims and necessary supporting information to EPA. As explained in the proposal (61 FR 68345), EPA issued in July 1992 the Adjunct Data File listing units of "nontraditional utilities". 57 FR 30034, 30040 (July 7, 1992). EPA indicated that the units might or might not be affected units and that, in any event, it lacked sufficient information on which to base any allowance allocation. *Id.* Further, EPA gave notice that if the data necessary for allowance allocation was not provided by September 8, 1992 for "a unit that may be affected now or in the future", the unit would not be allocated allowances. *Id.* Moreover, believing that it had corrected all timely identified errors in the data and resulting allocations, EPA stated in the March 23, 1993 notice on final allowance allocations that no allowances will be allocated to any affected unit that was not allocated allowances in that notice. 58 FR 15634, 15641 (March 23, 1993).

Neither Zinc Corporation of America nor the predecessor-owner (St. Joe Minerals Corporation) of the units now owned by Zinc Corporation of America submitted any data or any objection to the lack of allowance allocations for the units. The only companies that have units identified by EPA as potentially industrial utility-units and that submitted any comments concerning allowance allocations were LTV Steel Mining Company and Ford Motor Company. Both companies claimed that their units were not affected units, and neither has ever objected to the lack of allowance allocations.

Thus, there is no basis for allocating allowances now or in the future to industrial utility-units, as suggested by the commenter, if EPA ultimately determines that any such units do not qualify for the industrial utility-units exemption.¹¹ Such units are treated like

any other unit that has not been allocated allowances and becomes an affected unit after that date: No allowances will be allocated. EPA's approach of declining to allocate allowances when the deadline for submission of information for allowance allocation is missed has been upheld by the courts. *Texas Municipal Power Agency v. EPA*, 89 F.3d 858, 872-73 (1996).

III. Part 72: Interaction of Acid Rain Permitting and Title V

A. Relationship Between Acid Rain Rules and Parts 70 and 71

The proposal attempted to clarify the extent to which the Acid Rain rules apply in lieu of provisions of parts 70 and 71, which address permitting by State permitting authorities and by the Administrator under title V of the Act. No comments were received on these revisions. The revisions are adopted in today's rule with some changes. The language in several sections of the proposal stating that the Acid Rain rules "supersede" provisions of parts 70 or 71 is removed from the final rule because of concern that such language might cause confusion as to whether parts 70 and 71 remain in effect at all.

Instead, today's § 72.60 clarifies that part 72 governs, notwithstanding the requirements of part 71, and the list of specific procedural matters that part 72 governs is clarified and augmented so that the list includes all matters covered by subparts C, D, E, F, and H of part 72.¹² The list of specific matters to which part 71 still applies is also clarified. Further, today's § 72.70 retains the language in the existing rule stating that subpart G governs to the extent that the subpart is "inconsistent" with part 70. Upon reconsideration of the language, EPA concludes that this existing language is reasonably clear, particularly with the revisions in § 72.72 reducing the number of differences between subpart G and part 70. EPA also notes that the existing language avoids any potential confusion about the overall effectiveness of part 70.

B. State Authority to Administer and Enforce Acid Rain Permits

Under the proposal, a State becomes responsible for administering and enforcing Acid Rain permits for affected sources if the State has an operating permits program approved under part

companies that commented stated that it could not meet the proposed exemption requirements.

¹¹ EPA stresses that it has made no determination at this time on the qualification of these companies' units for the industrial utility-units exemption and will await submission of the necessary applications before making any determination. None of the

¹² For similar reasons, the same general approach is used in § 72.80, which states that subpart H, rather than part 70 or 71, governs revisions of Acid Rain permit provisions.

70 and to the extent the State Acid Rain regulations are accepted by the Administrator. The proposal also established a procedure for withdrawal of the Acid Rain Program from a State where the Administrator determines that the State is not adequately administering or enforcing the program.

Today's rule adopts the revisions, with several changes. Under the proposal, the Administrator accepts all or a portion of State Acid Rain regulations through issuance of a notice in the **Federal Register**. Particularly since the State regulations will then become part of the State title V operating permits program, EPA believes that notice and opportunity for public comment should be provided before the Administrator issues a final acceptance or rejection of all or a portion of the State regulations. This approach is consistent with the requirement in part 70 that notice and opportunity for public comment be provided on the Administrator's approval or disapproval of a State operating permits program under title V. See 40 CFR 70.4(e). Today's rule includes language that imposes a notice-and-comment requirement but is flexible enough to allow use of a direct final procedure under which, for example, the proposed and final acceptance of State regulations are issued in simultaneous notices and the acceptance becomes automatically final if no significant, adverse comments are timely submitted.

Further, the proposal revised the provision concerning the date by which a State permitting authority must reopen Phase II Acid rain permits to add Acid Rain NO_x requirements. The existing provision requires the permits to be reopened by January 1, 1999 but is unclear as to whether this is the deadline for completion, or simply commencement, of the reopening procedure. In order to clarify the provision and ensure that State permitting authorities have sufficient time to process the permits, the proposal stated that the reopening must be completed by July 1, 1999.

Commenters objected to the July 1, 1999 completion deadline on the ground that utilities need more than 6 months to plan for compliance with the NO_x terms of their Acid Rain permits. No comment was received supporting the Agency's concern that State permitting authorities might need additional time beyond January 1, 1999 to complete the reopening of the permit. Further, as discussed elsewhere in this preamble, today's rule includes provisions that enable State permitting authorities to expedite permit

processing, e.g., the provisions for elimination of newspaper notice and for use of direct proposed procedures. By further example, today's rule provides that any EPA-approved early election plan that has not been terminated must be added to the Phase II permit through an administrative amendment, rather than through a notice-and-comment procedure. This reflects the fact that § 76.8, governing early election plans, requires a State permitting authority to approve, as part of the Phase II permit, any ongoing early election plans previously approved by EPA. These streamlining provisions will reduce the administrative burden on the State permitting authorities.

Consequently, today's rule retains the January 1, 1999 deadline and makes it clear that the reopening of the permit to add NO_x requirements must be completed by that deadline. By its terms, the January 1, 1999 deadline for adding the NO_x provisions only applies to the extent that the provisions were included in a timely, complete permit application concerning NO_x emissions. EPA notes that, under § 76.9(b)(2), such permit application must be submitted by January 1, 1998 and that, where the State permitting authority with jurisdiction over the unit has responsibility for issuing Acid Rain permits covering NO_x, the submission should be made to that State permitting authority.

Finally, language is added (e.g., to § 72.73(b)(1) and § 72.74(a)) to make it clear that the State permitting authority issues Acid Rain permits to the extent that it has State Acid Rain regulations, accepted by EPA, that apply to the sources involved and to the Acid Rain requirements involved. For example, if accepted State Acid Rain regulations include the Acid Rain emissions limitation for SO₂ but not the emissions limitations for NO_x by the applicable deadline under § 72.73, EPA has the flexibility to determine whether the State permitting authority will be responsible for issuing Acid Rain permits covering both SO₂ requirements under part 72 and NO_x requirements under part 76.

C. Required Elements for State Acid Rain Program

The existing rule set forth the criteria for approval of a State operating permit program under title V and acceptance of the State Acid Rain regulations. The proposal eliminated or modified several of the criteria in the existing rule because EPA believed that they were unnecessary or redundant. Comments were received on only three of these revisions. With the changes discussed

below, all the revisions are adopted in today's rule for the reasons discussed here and in the proposal.

First, the existing rule required State permitting authorities to give written notice of draft permits to specified persons and also to provide notice in a newspaper or State publication. The proposal gave State permitting authorities the option of foregoing newspaper or State publication notice of draft permits that require only that a unit meet the standard SO₂ or NO_x emission limitations, a NO_x averaging plan, or a NO_x early election plan. Commenters supported this revision, which is adopted in today's rule.

Second, the proposal gave State permitting authorities the option of using what was referred to as a "direct final" procedure for issuing Acid Rain permits. Under the procedure, a State permitting authority issues simultaneously a draft permit and a proposed permit. If no significant, adverse comments are received, the proposed permit is deemed to be issued and, after the period for review by the Administrator, the State permitting authority issues the final permit. Commenters supported this option and urged that EPA clarify that it applies to permit revisions as well as permit issuance. EPA notes that the procedure is misnamed in the proposal in that the permit that is issued in the absence of significant, adverse comment is a "proposed permit" that is still subject to the Administrator's review.

Consequently, today's rule refers to this option as the "direct proposed" procedure and adopts the provision.¹³

With regard to the use of the direct proposed procedure for permit revisions, EPA notes that § 72.81(c)(2) in the proposal and in today's rule states that, with certain exceptions not relevant here, permit modifications must be treated as permit applications. Consistent with § 72.81(c)(2), the procedures for permit issuance (including, e.g., the direct proposed procedure) apply to permit modifications. Similarly, permit issuance procedures apply to permit reopenings. Because the other types of permit revisions, i.e., fast-track

¹³ Today's rule also removes language in § 72.72(b)(1)(iv) stating that after the comment period on a draft permit, the State permitting authority will issue or deny a proposed permit. Some State permitting authorities have provided, with EPA's concurrence, that the comment period on the draft permit and EPA's review of the permit run concurrently so long as no adverse comment is received and no change is made in the draft permit. The language in § 72.72 is removed in order to allow State permitting authorities to take this approach, which reduces the length of the permitting process, for Acid Rain permits.

modifications and administrative permit amendments, have their own procedures set forth in the proposal and today's rule, the direct proposed procedure does not apply to such revisions.

Third, the proposal eliminated a provision in the existing rule limiting the filing of State administrative or judicial appeals of an Acid Rain permit to no more than 90 days from the issuance of the permit. As a result, part 70, which imposes no limit on State administrative appeals and limits judicial appeals to no more than 90 days from permit issuance, would govern appeals of Acid Rain permits. 40 CFR 70.4(b)(3)(xii); *see also* 59 FR 44460, 44516 (August 29, 1994) (proposing to allow States to provide up to 125 days for judicial appeals).

Commenters objected to the removal of any limit on the periods for State administrative appeals, and for judicial appeals, under part 72. The commenters contended that, in the absence of a limit in part 72 (or in part 70) on administrative appeals, owners and operators "would never be able to know whether their permits would be subject to challenge". However, the commenters ignored the fact that, in imposing no federally mandated limit on State administrative appeals, part 72 leaves the matter to the States, which are highly likely to impose such limits in the interests of finality and administrative efficiency. EPA is not aware of any State operating permit programs that, to the extent they provided for administrative appeal, failed to set a time limit on the filing of administrative appeals. In short, the question here is not whether to have any limit but rather whether to leave the matter for the States or impose a federally mandated limit. EPA maintains that it is preferable to allow each State flexibility to craft time limits for Acid Rain appeals. Under this approach, each State can set a single time limit appropriate for and applicable to all administrative appeals—and also one for all judicial appeals—of the entire title V operating permit, rather than having one set of time limits for an Acid Rain permit and another set of time limits for the remaining portions of the operating permit.

The commenters contended that the Acid Rain permits are a "stand-alone portion" of the operating permit and so it would not be confusing to have a different deadline for appealing the Acid Rain portion and appealing the rest of the operating permit. EPA disagrees. Although the Acid Rain permit is a separate portion of the

operating permit, State permitting authorities are likely, as a matter of efficiency, to conduct notice and comment and other permitting procedures for the rest of the operating permit at one time and to issue a single, all inclusive operating permit, particularly since the Acid Rain permit is likely to comprise a relatively small part of the entire title V operating permit. In fact, in response to State concern over how to coordinate the processing of the Acid Rain permit and the operating permit, EPA has issued guidance on alternative approaches for achieving coordination. *See Guidance on Coordinating Title IV/Title V Permitting Schedules* (March 15, 1994). EPA believes that having a single administrative appeal deadline and a single judicial appeal deadline for the entire operating permit is simpler and less likely to result in inadvertent failure to meet the applicable filing deadline.

The commenters also alleged that the Acid Rain portion incorporates new compliance obligations while the remainder of the operating permit merely restates existing obligations. This, of course, depends on the timing of the issuance of the operating permit. State permitting authorities are allowed to phase in the issuance of operating permits and new obligations may arise before issuance of, and therefore may be included in, a given operating permit. Moreover, to the extent this distinction applies, it is likely to apply only for the initial Phase II Acid Rain permit; in most cases, a subsequent Acid Rain permit will restate the obligations (e.g., the requirement to hold sufficient allowances to cover SO₂ emissions) already in the initial Acid Rain permit.

EPA concludes that, with regard to the question of limiting State administrative and judicial appeals, the Acid Rain portions of operating permits should not be treated any differently than the remaining portions of operating permits. The provision in the proposal is adopted in today's rule.

In the proposal EPA noted that many States have already adopted Acid Rain rules based on the existing rule. EPA stated that it expected that, if rule revisions are adopted in final, States will incorporate the revisions within 2 years after the promulgation of the final rule. No comment was received on this approach, and EPA continues to believe that this is a reasonable time frame. To the extent a State permitting authority fails to incorporate the revisions in a timely manner, EPA will consider whether the State is adequately administering and enforcing the Acid Rain Program and may take action

under § 72.74 of today's rule to administer all or a part of the Acid Rain Program for sources located in the State.

IV. Part 72: Miscellaneous Permitting Matters

A. Definitions

The proposal modified or eliminated several definitions. Only one of the changes (i.e., the revised definition of "submit or serve" to eliminate the requirement for use of certified mail) received comment and that comment was supportive. The definition revisions, as modified below, are adopted in today's rule.¹⁴

B. Designated Representative

The proposal included two types of revisions concerning designated representatives. First, the procedures for selecting or changing the designated representative or an alternate were simplified and made less burdensome. Commenters supported the revisions, which are adopted in today's final rule.

Second, the proposal provided the option of selecting two alternate designated representatives for an affected source in certain limited circumstances. The proposal was aimed at providing flexibility for sources with units located in more than one State that are in a NO_x averaging plan under § 76.11 and that are subject to two levels of management, one at the subsidiary operating company and one at the parent company. In particular, as requested by a commenter, the proposal allowed a multi-state utility holding company with a NO_x averaging plan covering units in two or more States to designate for sources with units in the plan a single designated representative at the holding company level and two alternates, one at the management level and one at the operations level of the operating company. Commenters supported the additional flexibility but suggested certain changes to the proposal.¹⁵

¹⁴ One of the proposed definitions, "State", is modified in today's rule. The proposed definition removed language, stating that "State" has its conventional meaning where it is clear "from the context", and listed one specific instance where the conventional meaning would apply. Because there are several contexts in which the conventional meaning applies, today's rule retains the formulation in the existing rule. Thus, for example, in § 72.40(b)(2) the term "State" has its broader meaning (which includes the jurisdiction of any non-federal permitting authority) while in § 72.22(e)(1)(i) "State" has its conventional meaning.

¹⁵ One commenter suggested that there is no basis for the requirement in § 76.11 that units in a NO_x averaging plan have the same designated representative. This suggestion is outside the scope of the rulemaking. While it is unclear whether the commenter intended to raise that issue here, EPA

The commenter that originally requested this type of provision in the proposal expressed concern that the references in the proposal to a holding company with multiple subsidiaries may become obsolete in light of future restructuring of the electric industry. For example, a holding company with subsidiaries operating generation facilities may be restructured to include all generation facilities in a single subsidiary. This commenter also was concerned that the proposal limited the option of having two alternates to cases where the NO_x averaging plan covered all units operated by the subsidiaries. If any units are covered by early election plans or have alternative emission limitations and so are outside the NO_x averaging plan, the proposal would not apply. Other commenters echoed these concerns but suggested that EPA allow any source to have two alternates, regardless of whether the source has units that are in a NO_x averaging plan or are subject to management at both the subsidiary and parent company levels.

While retaining the general rule that a source must have one designated representative and may have one alternate, EPA proposed allowing two alternates in limited circumstances where it was shown that such flexibility might be needed. The proposed provision, as modified in today's rule, covers the only specific circumstance for which a need for multiple alternates has been explained by commenters, i.e., where units are in different States but in the same NO_x averaging plan and are subject to both subsidiary and parent company management. While commenters make a general suggestion that having two alternates gives greater assurance that a "point of contact" for a source will be available "at all times", the commenters do not claim that having one alternate has generally been insufficient or point to any other specific circumstances where two alternates are needed. EPA therefore declines to expand the provision any further.

For the reasons discussed here and in the proposal, today's rule adopts the proposed provision, with changes to meet other concerns stated by commenters. First, the provision expressly covers a unit whose utility system is the subsidiary of a company (not necessarily a "holding company"). Second, the provision will cover cases where the units in the NO_x averaging plan are operated by a single subsidiary or by two or more subsidiaries. Each unit must be in a utility-system

subsidiary of a company, but they may be in the same such subsidiary. Third, the NO_x averaging plan need not include all units operated by subsidiaries of the company; instead the plan must simply cover two or more units in more than one State.

C. Compliance Plans

The proposal revised the provisions concerning the submission of substitution plans and reduced utilization plans in order to clarify the deadlines and the procedures to be used. No comments were received, and the revisions are adopted in today's rule.

The proposal also revised the procedures for review of failed repowering projects. No comments were received on the revisions, which are adopted in today's rule.

Finally, the proposal revised the deadline for activating conditional repowering extension plans from December 31, 1997 to July 1, 1997. No comments were received. However, today's rule is being published after July 1, 1997, and EPA has decided not to revise the activation deadline retroactively.

D. Federal Permit Issuance

The proposal made several revisions to the federal permit issuance procedures. For example, the period after which an Acid Rain permit application received by EPA is deemed to be complete was lengthened from 30 days to 60 days. This was done in order to be consistent with part 71, under which the period applicable to operating permit applications is 60 days. Commenters objected that this prolongs the "period of uncertainty" over the completeness of the Acid Rain application and stated that Acid Rain permitting "generally proceeds along a separate track" from other title V permitting. However, the commenters' assumption that the Acid Rain portion of the operating permit is processed separately from the rest of the operating permit is not necessarily correct. If the State permitting authority is generally responsible for issuing title V operating permits but, because its Acid Rain rules are not fully approved, EPA issues the Acid Rain permits, then the Acid Rain permits may be processed separately. In cases where EPA is responsible for issuing entire title V operating permits (including the title IV portion), the title IV and title V procedures may be coordinated as a matter of efficiency, particularly if EPA delegates the title IV and title V permitting to the State. See 40 CFR 71.10 (delegation of permitting under title I); and 72.74(a)(2) of today's

rule (delegation of permitting under title IV). A single completeness review (as well as a single notice and comment procedure) may be conducted for the entire operating permit. EPA maintains that the ability to coordinate Acid Rain permitting and title V permitting and to realize potential efficiencies is enhanced by minimizing the differences between Acid Rain permitting and title V permitting.

Moreover, the Acid Rain portion of the operating permit is generally relatively small compared to the entire title V permit application. It is therefore logical to make the completeness review period for the title IV permit conform to the 60-day period for title V permits, rather than to shorten the title V completeness review period to 30 days. While the period during which owners and operators are uncertain about the completeness of Acid Rain permit applications will be lengthened for 30 days, EPA maintains that the advantage of a consistent completeness review period outweighs the relatively minor, additional uncertainty.

Further, the proposed rule altered the provision concerning the time period within which a designated representative must respond to a request for supplemental information by the Administrator. While the existing rule set an automatic 30-day period for responding and allowed the Administrator to lengthen the response period, the proposal stated that a reasonable period would be set on a case-by-case basis by the Administrator. A commenter objected on the ground that it is unlikely that a period less than 30 days would be reasonable and that it would generally be in the interest of a designated representative to respond expeditiously. However, the commenter ignores the fact that there can be significant, but readily remedied gaps or errors in the information submitted to EPA in a permit application. Setting a minimum response period of 30 days is likely to lengthen unnecessarily the permitting process. In addition, while the Agency could treat applications with such errors as incomplete and avoid the minimum 30-day response period, EPA maintains that it is preferable to have the flexibility to set a reasonable, short response period. This flexible approach both promotes orderly and expeditious processing of permits and protects the designated representative from unreasonable requests. This is also preferable to the commenter's approach of assuming that designated representatives will necessarily respond expeditiously and in a time frame that meets the Agency's schedule for permit processing.

did not propose, and is not considering here, such a change in § 76.11.

E. Permit Revision

The proposal made several changes to the permit revision procedures. Changes concerning permit reopenings received no comment and are adopted in the final rule; changes concerning fast-track amendments and administrative amendments are adopted as discussed below.

With regard to fast-track modifications, the proposal lengthened the period within which a State permitting authority must act on a fast-track modification of a permit from 30 to 60 days after the end of the public comment period. Commenters objected claiming that there is no evidence that State permitting authorities need more time and that the revisions entitled to fast-track modification required little exercise of administrative discretion and are unlikely to receive public comment.

EPA notes that, while a NO_x averaging plan or plan change may require little administrative discretion and elicit little comment, the processing of other types of revisions (e.g., changes to repowering plans or thermal energy plans) is more likely to involve discretion or public comment. Further, the processing of Acid Rain permits and permit revisions represents a very small portion of the operating permit processing required of State permitting authorities under title V. Reflecting the significant burden of operating permit processing, part 70 allows State permitting authorities to take up to 18 months from receipt of a complete permit application to issue an operating permit and a similar period to make significant modifications to an existing operating permit. 40 CFR 70.7(a)(2) and (e)(4)(ii). By comparison, a 90-day period (i.e., the 30-day comment period and 60 days after the end of the period) for completing a fast-track modification is certainly expedited. EPA maintains that, in light of the permitting burden faced by State permitting authorities, it is preferable to set a more realistic, and yet still expedited, deadline for action by State permitting authorities.

With regard to administrative amendments, the proposal set forth the amendment procedures in detail, rather than citing the procedures in part 70. Further, the period for action on one administrative amendment, an alternative emission limitation (AEL) demonstration period, was lengthened from 30 days to 60 days after receipt of an AEL demonstration period petition determined by the permitting authority to meet all the requirements of § 76.10. No comments were made on these

revisions, which are adopted in today's rule.

In addition, the administrative amendment procedures were changed to allow a permitting authority to correct minor errors in a permit on its own motion. Noting that the proposed provision was not explicitly limited to "minor" errors, commenters argued that notice should be given to the designated representative before even minor changes are made to the permit. In response to these concerns, today's rule explicitly limits administrative permit amendments on the motion of the permitting authority to corrections of typographical errors or similarly noncontroversial changes (e.g., adding a new units or retired units exemption for which the requirements were previously met). Moreover, the rule requires that a permitting authority provide at least 30 days' notice to the designated representative of the source involved before making, on its own motion, any administrative permit amendments. This approach will enable the permitting authority to correct minor errors with minimal delay while providing the designated representative the opportunity to comment.

In order to make the reopening provision consistent with the provision allowing a permitting authority to make administrative amendments on its own motion, language is added to § 72.85. This language makes it clear that administrative amendment procedures, rather than reopening procedures, may be used for typographical or similar errors.

F. Reduced Utilization Accounting

The proposal made several changes in the reduced utilization accounting provisions. Most of the changes received no comment or only favorable comment and are adopted in today's rule. Commenters objected to one change: The provision that, in accounting for the effect of heat rate improvements on a Phase I unit's utilization, credit for such improvements must be limited to the net effect of the improvements on the unit's heat rate. According to the commenters, if a unit's heat rate (i.e., Btu/Kwh) since the 1985–1987 base period deteriorates (i.e., increases) and measures are taken that offset that deterioration, the entire effect of the heat rate improvements should be included in accounting for reduced utilization. The commenters alleged that the statutory reduced utilization provision in section 408(c)(1)(B) of the Act establishes a "baseline" heat input, not a "baseline" heat rate.

In asserting that there is no connection between utilization in the

base period and heat input in the base period, the commenters ignore the basic purpose of accounting for reduced utilization and heat rate improvements. The purpose of the reduced utilization provisions is to ensure that any increased emissions resulting from reducing utilization of, and shifting generation from, Phase I units to units compensating for the reduced utilization "are accounted for in the allowance system." 56 FR 63002, 63019 (December 3, 1991). Reduced utilization "as a result of * * * improved unit efficiency programs" need not be accounted for through allowance surrender because these programs "cause decreases in utilization without any shifts of generation to unaffected units." 56 FR 63021. To the extent utilization (i.e., total annual heat input in mmBtus) at a Phase I unit is reduced below the baseline level because that unit has improved its heat rate after 1987 *over the level reflected in the baseline utilization*, there is no increase in SO₂ emissions and allowances need not be surrendered. In this case, the Phase I unit is using less fuel because it can produce a kilowatt-hour of electricity with less fuel and thus less SO₂ emissions.

However, if the Phase I unit's heat rate deteriorates from the level reflected in the unit's baseline utilization and heat rate improvement measures are instituted after 1987 that bring heat rate back to the level reflected in the baseline utilization, then the unit is using the same amount of fuel to produce a kilowatt-hour of electricity. In the latter case, the heat rate improvements made after 1987 do not account for the use of less fuel at the Phase I unit. Just as heat rate improvements made before 1987 and reflected in baseline utilization cannot account for utilization below baseline, heat rate improvements made after 1987 that simply restore the heat rate to the level reflected in the baseline cannot account for reduced utilization. See 61 FR 68354. The same logic applies if a Phase I unit is attempting to account for its reduced utilization through heat rate improvements at another unit that simply restore the latter unit's heat rate to the 1987 level.

Thus, contrary to the commenters' assertions, EPA did not simply "assume" that limiting heat rate improvement to net improvement since 1987 is warranted. On the contrary, EPA explained, albeit in less detail than in today's rule, the basis for the limitation. *Id.* Moreover, the limitation is consistent with long-standing explanations of the purpose of reduced utilization accounting, as discussed

above, and with other, regulatory provisions governing such accounting. In particular, limiting heat rate improvement to net improvement since 1987 is analogous to the approach taken in the existing rule concerning sulfur-free generation, which is not at issue here. Only the net increase in current generation at a sulfur-free generator (i.e., the increase in current generation over the sulfur-free generator's average 1985–1987 annual generation), not the increase from one year to the next, is used to account for reduced utilization. See 40 CFR 72.91(a)(3)(iii); and 58 FR 3590, 3606–7 (January 11, 1993).¹⁶ The commenters' approach is therefore rejected as inconsistent with the entire thrust of reduced utilization accounting, and the proposed provision is adopted in today's rule.

V. Part 73: Allowances

A. Allowance Tables

In the proposal, EPA proposed a number of changes in unadjusted allowances and in the units and allowance figures listed in Tables 2 and 3 of § 73.10, reflecting those allowance changes. For purposes of the proposal, EPA was able to list the changes in the rule without reprinting Tables 2 and 3. However, consistent with the requirements of the **Federal Register** concerning finalization of multiple changes to regulatory tables and in the interest of facilitating public understanding of the final changes, EPA concludes that the changes should be finalized through republication of information in the tables. Further, section 403(a) of the Act requires the Administrator to issue prior to June 1, 1998 a revision of the final allowance allocations primarily to account for allocations for repowered units under section 409. That revision will necessitate recalculation of all units' allowance allocations and so must also be implemented through republication of information in Tables 2 and 3. In order to avoid the confusion likely to result from, and the large expense associated with, multiple republications of information in the tables, EPA has decided not to finalize at this time the allowance revisions in the December 27, 1996 rule. Instead, EPA intends to

propose in the near future the revisions associated with the June 1, 1998 allocations and to coordinate finalization of both the allowance revisions in the December 27, 1996 proposal and that future proposal.

The only exception to this approach is the allowance changes for Central Louisiana Electric Company's Rodemacher unit 2. In the December 27, 1996 proposal, the allowances for Rodemacher unit 2 were changed to 20,774 unadjusted allowances. Under a settlement of litigation concerning Rodemacher unit 2's allowance allocation, the Administrator agreed to sign a final rule adopting the revision to the unit's allowances by October 1997. Consistent with that settlement, the proposed unadjusted allowances for Rodemacher unit 2 are adopted in today's rule. This single change can be made without republishing the allowance tables.

B. Small Diesel Refinery Provisions

The proposal made certain revisions to the provisions to small refinery allowance allocations. No comment was received, and the revisions are adopted in today's rule.

VI. Part 75: Monitoring of Units Burning Digester or Landfill Gas

In the proposal, EPA requested comment on monitoring requirements for units burning digester or landfill gas. No comments were received. EPA intends to consider this matter in future proceedings.

VII. Part 77: Excess Emissions

The proposal made changes to part 77 concerning immediate deduction of allowances to offset excess emissions, the deadline for paying excess emissions penalties, and excess NO_x emissions under a NO_x averaging plan. The changes received no comment or only favorable comment and are adopted in the final rule.

VIII. Part 78: Administrative Appeals

The proposal made changes to part 78 to clarify that an administrative appeal is a prerequisite for judicial review of decisions of the Administrator under the Acid Rain Program and to ensure that the requirement for exhaustion of administrative remedies is consistent with the Supreme Court's decision in *Darby v. Cisneros*, 509 U.S. 137 (1993). On September 24, 1993, the Agency originally proposed to add language stating explicitly that administrative appeal is a prerequisite for judicial review. 58 FR 50088, 50104 (1993). Certain commenters stated, in response to the September 24, 1993 proposal,

that, in light of the alleged potential for "disruptive effects" resulting from an administrative exhaustion requirement, the Agency should solicit additional comment on the effect of *Darby* on part 78. EPA therefore did not finalize the September 24, 1993 proposal. Instead, EPA provided further opportunity for comment by publishing the December 27, 1996 proposal, which included both the changes explicitly requiring exhaustion of administrative remedies and some additional changes to conform with *Darby*. In its comments on the December 27, 1996 proposed rule, the same commenters submitted further comments. In their second set of comments, the commenters failed to go beyond their generalized claim of "disruptive effects". Rather than providing any specific claims or examples of when administrative appeal of a particular type of Administrator's decision would be "disruptive" to the Acid Rain Program or to affected sources' compliance efforts, the commenters simply expressed general concern that EPA "failed to consider" unspecified "disruptive" effects.

In the September 24, 1993 and December 27, 1996 proposals, EPA set forth both the basis for requiring exhaustion of administrative remedies and provisions addressing concerns over delay pending completion of administrative review. Requiring exhaustion of administrative remedies promotes efficient use of administrative and judicial resources in that it "allows the Agency to review * * * decisions for correctness before having to defend (them) * * * in Federal court." 58 FR 50104 (quoting the original proposed appeals procedures at 56 FR 63002, 63033 (December 3, 1991)). Decisions that a petitioner shows are erroneous can be reversed or corrected without resource-intensive litigation before the federal courts and decisions that a petitioner shows are insufficiently explained can be reexamined and either reversed or better explained. The overall effect is to increase the likelihood of sound decision-making and reduce the need for recourse to the courts.¹⁷

¹⁷ EPA maintains that, contrary to commenters' assertion, the provision in section 307(b)(1) of the Clean Air Act on motions for reconsideration is irrelevant to the question of administrative appeals and is not properly interpreted as evidencing "hostility" to the exhaustion requirement involved here. Section 307(b)(1) involves judicial appeals and the effect of agency reconsideration of a final action on such appeals. To the extent section 307(b)(1) addresses reconsideration of a final rule, the section is irrelevant to this case, which concerns administrative appeals of individual, adjudicative decisions. To the extent the section addresses reconsideration of an adjudicative decision, the section is still irrelevant here. Reconsideration

¹⁶ While EPA uses 1985–1987 average sulfur-free generation as the bench mark for limiting the use of sulfur-free generation in reduced utilization accounting, the proposal and today's rule use 1987 heat rate as the bench mark for limiting the use of unit efficiency improvements. This is because annual generation was more likely to vary during 1985–1987 than was a unit's annual heat rate and the use of the 1987 heat rate, which captures any efficiency improvement measures instituted before 1988, is less burdensome for utilities and EPA to determine than the average 1985–1987 heat rate.

Further, while nothing in the record indicates that delay pending administrative appeal of Acid Rain Program decisions (during which appeal the decisions will not be operative) will likely have "significant, adverse consequences", the December 27, 1993 proposal took reasonable account of the general possibility of such consequences pending appeal.¹⁸ 61 FR 68365. Despite two opportunities to provide information on the alleged, potential, adverse effect of the exhaustion requirement, the commenters originally objecting to the requirement were apparently unable to identify any specific circumstances in the Acid Rain Program under which significant, adverse consequences would result from the requirement, much less provide any information on the likelihood of such circumstances arising. No such circumstances have been identified to EPA, and EPA is not aware of any, particularly in light of the ability of the Agency, under the proposal and today's rule, to expedite administrative appeals. EPA therefore rejects the commenters' claim concerning "disruptive effects" of the exhaustion requirement as speculative and unsupported.

Moreover, the Agency's general approach under the regulatory statutes that it administers is to require exhaustion of administrative remedies prior to judicial review. *See, e.g.*, 40 CFR 71.11(l)(4) (administrative appeal of final permit decision under title V of Clean Air Act); 40 CFR 124.19(f)(1) (administrative appeal of final permit decision under the Solid Waste Disposal Act as amended by the Resource Conservation and Recovery Act (RCRA), Prevention of Significant Deterioration (PSD) program in the Clean Air Act, or Underground Injection Control (UIC) program in the Safe Drinking Water Act); and 40 CFR 124.60(g) (administrative appeal of final permit decision under National Pollutant Discharge Elimination System (NPDES)). Today's rule is consistent with that general approach.

Nevertheless, the Agency crafted the proposed rule for Acid Rain Program appeals to provide for flexibility to minimize delay, particularly if future

cases arise where delay will have a significant, adverse effect. Specifically, the proposal revised the existing rule to allow the Administrator, the Environmental Appeals Board, or the Presiding Officer (as appropriate) to set different, reasonable time periods (which could be shorter or longer than in the existing rule) for administrative appeal-related filing by parties. For example, the 30-day period within which motions to intervene in part 78 appeals may be filed was changed to allow a different period to be set. As explained in the proposal, this approach gives the Agency "the ability to accelerate the appeals proceeding where delay due to the pending appeal will have significant, adverse consequences." 61 FR 68365. The commenters argued that the Agency might not always "share an affected source's interest in avoiding" such adverse consequences. However, the Agency's approach of allowing adjustment of the time periods gives the Agency the authority to accommodate the need for expeditious administrative appeal and gives the affected source the opportunity to show that expedition is necessary. Particularly in cases where such a showing is made, the Agency intends to make reasonable efforts to minimize the delay caused by the appeal. The Agency maintains that this approach reasonably balances, on one hand, the important role of the exhaustion requirement and, on the other, the commenter's generalized concern that appeals not cause undue delay.

The commenters failed to recommend any other approach but merely stated that the Agency had not considered limiting the applicability of the exhaustion requirement, foregoing the exhaustion requirement, or setting tighter time limits on procedural steps. However, in explaining the need for the exhaustion requirement (*see* 56 FR 63033, 58 FR 50104, and 61 FR 68365), the Agency rejected the notion of limiting or foregoing the requirement. Further, recognizing that the major purpose of providing flexibility in the time periods for filings is to expedite administrative appeals, EPA is modifying the proposal to provide that, with a few exceptions discussed below, the time periods involved may be shortened, but not lengthened.

One of the more important exceptions to that approach is the period for filing of administrative appeals.¹⁹

¹⁹ A minor exception under today's rule is the period for curing defects in filings, which remains as 7 days subject to shortening or lengthening at the discretion of the Environmental Appeals Board or

Commenters raised concern that an Administrator's decision under the Acid Rain Program would remain "in limbo" during a period of uncertain duration for the filing of an administrative appeal. Today's rule reduces the standard period for appeal to 30 days from issuance of the Administrator's decision and establishes that as a fixed period that cannot be changed on a case-by-case basis. The Agency is concerned that a period shorter than 30 days would not provide enough time for preparation of a petition that fully addresses the issues on appeal, as required under § 78.3(c). *See, e.g.*, 40 CFR 78.3(c)(1) and (3) (requiring a list of material issues and a clear and concise brief supporting the petition). This standard appeal period is consistent with the 30-day time period for administrative appeal of other actions of the Administrator under the Clean Air Act and other statutes administered by EPA. *See, e.g.*, 40 CFR 71.11(l)(1) (administrative appeal of final permit decision under title V); 40 CFR 124.19(a) (administrative appeal of final permit decision under RCRA, PSD program, or UIC program); and 40 CFR 124.91(a)(1) (administrative appeal of final permit decision under NPDES). The reduced time period for filing appeals reduces the period of uncertainty on the status of the decision while still providing a reasonable opportunity for administrative appeal.²⁰

From the time a decision is issued until the expiration of the appeal period, there is necessarily some uncertainty about the status of the decision: the parties will not know for certain whether the decision will be final until the expiration of the appeal period. However, this uncertainty is tempered by the fact, admitted by the commenters, that the vast majority of decisions under the Acid Rain Program have not been, and probably will not be, appealed. Further, the limitations on the presenting of new evidence and on the raising of new issues during an administrative appeal of a decision for which there was an opportunity to comment will encourage parties interested in a decision to submit comments. As a result, parties' positions will probably be known when the decision is issued and the likelihood of appeal can then be evaluated.

the Presiding Officer. This will minimize the likelihood of a filing being permanently excluded for purely technical reasons. The Agency is confident that flexibility concerning this limited type of procedural deadline can be implemented in a way that will not result in unnecessary delay of proceedings.

²⁰ For similar reasons, the period for appealing a proposed decision of a Presiding Officer to the Environmental Appeals Board is fixed at 30 days under § 78.20(a).

provides a second opportunity for agency review of an adjudicative decision, for which an opportunity for administrative review was already provided. In contrast, the issue here is whether there should be an *initial* opportunity for EPA to review its decisions on Acid Rain matters before the decisions may be appealed to the courts.

¹⁸ EPA did not "acknowledge" that there would be cases of "significant, adverse consequences" due to delay pending appeal or that any such cases would be likely to occur. Instead, EPA provided procedures that could address such cases (regardless of their likelihood) if they arose.

The commenters also suggested that a decision should be considered operative during the period between the date the decision is issued and the expiration of the appeal period (i.e., 30 days under today's rule) unless and until a petition for administrative appeal is filed with the Environmental Appeals Board. Prior to today's rule revisions, part 78 provided that a decision was operative from the date of issuance and throughout the administrative appeal period, except to the extent the decision was stayed by the Environmental Appeals Board or the Presiding Officer designated by the Board. 40 CFR 78.7(a). While today's rule makes a decision inoperative once a timely petition for administrative appeal is filed, the status of the decision prior to appeal or the running of the period for filing an appeal is unchanged. The decision itself (e.g., the approval or denial of an Acid Rain permit or permit revision or of a petition under part 75) may specify the date on which the decision is effective. Unless the decision itself specifies an effective date that is different than the date on which the decision is actually issued, the decision is operative on the issuance date unless and until the filing of a timely petition for administrative appeal in accordance with part 78. For example, with regard to a decision concerning the transfer of allowances to or from an Allowance Tracking System Account, the requirement in the existing rule that the Administrator implement, within 5 business days of receipt, an allowance transfer request that he or she determines to be properly submitted (40 CFR 73.52 and 73.53) is unchanged in the December 27, 1996 proposal and today's rule. In principle, if the transfer were appealed under part 78, the Administrator could take action to render the transfer inoperative pending appeal. However, appeal in such circumstances is highly unlikely since an allowance transfer must be authorized by the designated representative of the party transferring the allowances. See 42 U.S.C. 7651b(b).

For the reasons discussed here and in the September 24, 1993 and December 27, 1996 proposals, the December 27, 1996 revisions are adopted as modified above.

IX. Administrative Requirements

A. Executive Order 12866

Under Executive Order 12866, 58 FR 51735 (October 4, 1993), the Administrator must determine whether the regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive

Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of \$100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this final rule is a "significant regulatory action" because the rule seems to raise novel legal or policy issues. As such, this action was submitted to OMB for review. Any written comments from OMB to EPA, any written EPA response to those comments, and any changes made in response to OMB suggestions or recommendations are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the ADDRESSES section of this preamble.

B. Unfunded Mandates Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104-4, establishes requirements for federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, before promulgating a proposed or final rule that includes a federal mandate that may result in expenditure by State, local, and tribal governments, in aggregate, or by the private sector, of \$100 million or more in any one year. Section 205 generally requires that, before promulgating a rule for which a written statement must be prepared, EPA identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least

burdensome alternative if the Administrator explains why that alternative was not adopted. Finally, section 203 requires that, before establishing any regulatory requirements that may significantly or uniquely affect small governments, EPA must have developed a small government agency plan. The plan must provide for notifying any potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Because this final rule is estimated to result in the expenditure by State, local, and tribal governments or the private sector of less than \$100 million in any one year, the Agency has not prepared a budgetary impact statement or specifically addressed the selection of the least costly, most cost-effective, or least burdensome alternative. Because small governments will not be significantly or uniquely affected by this rule, the Agency is not required to develop a plan with regard to small governments.

For the reasons discussed in detail here and in the proposal (61 FR 68340), the final rule has the net effect of reducing the burden of parts 72, 77, and 78 of the Acid Rain regulations on regulated entities (including both investor-owned and municipal utilities) and on State permitting authorities (which may include State, local, and tribal governments). For example, the final rule reduces the burden of obtaining or providing new units and retired units exemptions from the Acid Rain Program and of issuing Acid Rain permits.

The final revisions to part 73 also do not have a significant, adverse effect on regulated entities (including small entities) and have no effect on State permitting authorities. The final rule increases the annual unadjusted basic allowances for one unit by 2,312 allowances. In a future action, the Agency will act on the other allowance revisions in the proposal. Sections 403(a) and 405(a)(3) of the Act set a nationwide cap on annual allowance allocations. Because of the requirement to adhere to the cap, the increase of allowances under this final rule (if not offset by the other allowance revisions when they are finalized) would eventually necessitate an equal decrease in the total annual allocations of all other units. The small decrease (i.e., 2,312 allowances out of an annual

nationwide cap of about 8.95 million allowances or about 0.026 percent) would be spread among all other units, and so the effect on any one unit would be insignificant. Moreover, EPA is not, in today's rule, adjusting the allocations of the other units to account for this small allowance increase.

C. Paperwork Reduction Act

OMB has approved the information collection requirements contained in this final rule under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.*, and has assigned OMB control number 2060-0258.

The only additional information required by this collection of information is data concerning industrial utility-units that exercise the option of applying for the industrial utility-units exemption established by today's rule. If granted, the industrial utility-units exemption exempts the unit from most requirements of the Acid Rain Program, e.g., allowance, monitoring, and annual compliance requirements. The requirements from which qualified industrial utility-units will be exempt are significantly more burdensome than the information collection requirements for obtaining the exemption.²¹ An industrial utility-unit seeking the exemption must meet the information collection requirements, which involve submission of information that is necessary, and will be used, for determining whether the unit qualifies and will continue to qualify for the exemption.

The additional information collection increases the estimated burden, as compared to the burden under the existing rule, by an average of 24 hours per response for an estimated 15 one-time responses. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a federal agency. This includes the time needed to: Review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting,

validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9. EPA is amending the table in 40 CFR part 9 of currently approved ICR control numbers issued by OMB for various regulations to list the information requirements contained in this final rule.

D. Regulatory Flexibility

The Regulatory Flexibility Act, 5 U.S.C. 601, *et seq.*, requires federal agencies to consider potential impacts of its regulations on small entities. Under 5 U.S.C. 604(a), an agency issuing a notice of final rulemaking under section 553 of the Administrative Procedure Act, must prepare and make available for public comment a final regulatory flexibility analysis. Such an analysis is not required if the head of an agency determines, under 5 U.S.C. 605(b), that the final rule will not have a significant economic impact on a substantial number of small entities.

In the preamble of the January 11, 1993 rule, the Administrator certified that the rule, including the provisions revised by today's rule, would not have a significant, adverse impact on small entities. 58 FR 3649. Today's final revisions are not significant enough to change the overall economic impact addressed in the January 11, 1993 preamble. Moreover, as discussed in this preamble, today's rule has the net effect of reducing the burden of the Acid Rain regulations on regulated entities, including small entities. For example, the rule makes it less burdensome to obtain new units and retired units exemptions from the Acid Rain Program. Further, the rule increases the allowances for one unit, which increase will have an insignificant effect on other units' allowance allocations.

For the reasons discussed above, EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has determined that this rule will not have a significant, economic

impact on a substantial number of small entities.

E. Submission to Congress and the General Accounting Office

Under 5 U.S.C. 801(a)(1)(A) as added by the Small Business Regulatory Enforcement Fairness Act of 1996, EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the General Accounting Office prior to publication of the rule in today's **Federal Register**. This rule is not a "major rule" as defined by 5 U.S.C. 804(2).

F. Miscellaneous

In accordance with section 117 of the Act, issuance of this final rule was preceded by consultation with any appropriate advisory committees, independent experts, and federal departments and agencies.

List of Subjects in 40 CFR Parts 9, 72, 73, 74, 75, 77, and 78

Environmental protection, Acid rain, Administrative practice and procedure, Air pollution control, Compliance plans, Continuous emissions monitors, Electric utilities, Intergovernmental relations, Nitrogen oxides, Penalties, Permits, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: October 6, 1997.

Carol M. Browner,
Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 9—[AMENDED]

1. The authority citation for part 9 continues to read as follows:

Authority: 7 U.S.C. 135, *et seq.*, 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331j, 346a, 348; 31 U.S.C. 9701; 33 U.S.C. 1251, *et seq.*, 1311, 1313d, 1314, 1321, 1326, 1330, 1342, 1344, 1345(d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975 Comp. p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–1, 300j–2, 300j–3, 300j–4, 300j–9, 1857, *et seq.*, 6901–6992k, 7401–7671q, 7542, 9601–9657, 11023, 11048.

§ 9.1 [Amended]

2. Section 9.1 is amended by adding to the table under Permits Regulation in the column "40 CFR Citation", after the entry for "72.7–72.10", the entry "72.14" and adding to the table, as the corresponding entry in the column "OMB Control No.", the entry "2060–0258".

²¹ Because the information collection burden on industrial utility-units in the absence of this new exemption was not included in the ICR for the existing rule, the effect of removing such burden through the new exemption is not included in the ICR for today's rule. Consequently, the ICR for today's rule shows an increase in burden even though exempt industrial utility-units will actually experience a significant net reduction in the burden imposed on them by the Acid Rain Program. In addition, as discussed in this preamble, today's rule includes other revisions that will reduce somewhat the burden of the program on units that are not exempt. Because the burden reduction for non-exempt units is small relative to the total burden of the program, the reduction is not reflected in the ICR for today's rule.

PART 72—[AMENDED]

3. The authority citation for part 72 is revised to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

§ 72.1 [Amended]

4. Section 72.1 is amended by removing from paragraph (b) the words "part 70" and adding, in their place, the words "parts 70 and 71".

5. Section 72.2 is amended by: removing the definition for "Dispatch system"; adding in alphabetical order the definitions for "Affected States" and "Eligible Indian tribe"; and revising paragraphs (1)(i) and (2) of the definition for "Acid Rain emissions limitation", the definition for "Acid Rain permit or permit", paragraph (2) of the definition of "Coal-fired", the definitions for "Customer" and "Permitting authority" and "Phase I unit", paragraph (3) of the definition of "Power purchase commitment", and the definitions for "Submit or serve" and "State" and "State operating permits program" to read as follows:

§ 72.2 Definitions.

* * * * *

Acid Rain emissions limitation means:

(1) * * *

(i) The tonnage equivalent of the allowances authorized to be allocated to an affected unit for use in a calendar year under section 404(a)(1), (a)(3), and (h) of the Act, or the basic Phase II allowance allocations authorized to be allocated to an affected unit for use in a calendar year, or the allowances authorized to be allocated to an opt-in source under section 410 of the Act for use in a calendar year;

* * * * *

(2) For purposes of nitrogen oxides emissions, the applicable limitation under part 76 of this chapter.

* * * * *

Acid Rain permit or permit means the legally binding written document or portion of such document, including any permit revisions, that is issued by a permitting authority under this part and specifies the Acid Rain Program requirements applicable to an affected source and to the owners and operators and the designated representative of the affected source or the affected unit.

* * * * *

Affected States means any affected States as defined in part 71 of this chapter.

* * * * *

Coal-fired means * * *

(2) For all other purposes under the Acid Rain Program, except for purposes

of applying part 76 of this chapter, a unit is "coal-fired" if it uses coal or coal-derived fuel as its primary fuel (expressed in mmBtu); *provided that*, if the unit is listed in the NADB, the primary fuel is the fuel listed in the NADB under the data field "PRIMEFUEL".

* * * * *

Customer means a purchaser of electricity not for the purposes of retransmission or resale. For generating rural electrical cooperatives, the customers of the distribution cooperatives served by the generating cooperative will be considered customers of the generating cooperative.

* * * * *

Eligible Indian tribe means any eligible Indian tribe as defined in part 71 of this chapter.

* * * * *

Permitting authority means either:

(1) When the Administrator is responsible for administering Acid Rain permits under subpart G of this part, the Administrator or a delegatee agency authorized by the Administrator; or

(2) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to administer Acid Rain permits under subpart G of this part and part 70 of this chapter.

* * * * *

Phase I unit means any affected unit, except an affected unit under part 74 of this chapter, that is subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitation beginning in Phase I; or any unit exempt under § 72.8 that, but for such exemption, would be subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitation beginning in Phase I.

* * * * *

Power purchase commitment means a commitment or obligation of a utility to purchase electric power from a facility pursuant to:

* * * * *

(3) A letter of intent or similar instrument committing to purchase power (actual electrical output or generator output capacity) from the source at a previously offered or lower price and a power sales agreement applicable to the source is executed within the time frame established by the terms of the letter of intent but no later than November 15, 1993 or, where the letter of intent does not specify a time frame, a power sale agreement applicable to the source is executed on or before November 15, 1993; or

* * * * *

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other equivalent means of dispatch, or transmission, and delivery. Compliance with any "submission", "service", or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

* * * * *

State means one of the 48 contiguous States and the District of Columbia, any non-federal authorities in or including such States or the District of Columbia (including local agencies, interstate associations, and State-wide agencies), and any eligible Indian tribe in an area in such State or the District of Columbia. The term "State" shall have its conventional meaning where such meaning is clear from the context.

State operating permit program means an operating permit program that the Administrator has approved under part 70 of this chapter.

* * * * *

6. Section 72.6 is amended by adding paragraph (b)(9) and revising paragraphs (c)(1) and (2) to read as follows:

§ 72.6 Applicability.

* * * * *

(b) * * *

(9) A unit for which an exemption under § 72.7, § 72.8, or § 72.14 is in effect. Although such a unit is not an affected unit, the unit shall be subject to the requirements of § 72.7, § 72.8, or § 72.14, as applicable to the exemption.

(c) A certifying official of an owner or operator of any unit may petition the Administrator for a determination of applicability under this section.

(1) *Petition Content.* The petition shall be in writing and include identification of the unit and relevant facts about the unit. In the petition, the certifying official shall certify, by his or her signature, the statement set forth at § 72.21(b)(2). Within 10 business days of receipt of any written determination by the Administrator covering the unit, the certifying official shall provide each owner or operator of the unit, facility, or source with a copy of the petition and a copy of the Administrator's response.

(2) *Timing.* The petition may be submitted to the Administrator at any time but, if possible, should be submitted prior to the issuance (including renewal) of a Phase II Acid Rain permit for the unit.

* * * * *

7. Section 72.7 is revised to read as follows:

§ 72.7 New units exemption.

(a) *Applicability.* This section applies to any new utility unit that has not previously lost an exemption under paragraph (f)(4) of this section and that, in each year starting with the first year for which the unit is to be exempt under this section:

(1) Serves during the entire year (except for any period before the unit commenced commercial operation) one or more generators with total nameplate capacity of 25 MWe or less;

(2) Burns fuel that does not include any coal or coal-derived fuel (except coal-derived gaseous fuel with a total sulfur content no greater than natural gas); and

(3) Burns gaseous fuel with an annual average sulfur content of 0.05 percent or less by weight (as determined under paragraph (d) of this section) and nongaseous fuel with an annual average sulfur content of 0.05 percent or less by weight (as determined under paragraph (d) of this section).

(b)(1) Any new utility unit that meets the requirements of paragraph (a) of this section and that is not allocated any allowances under subpart B of part 73 of this chapter shall be exempt from the Acid Rain Program, except for the provisions of this section, §§ 72.2 through 72.6, and §§ 72.10 through 72.13.

(2) The exemption under paragraph (b)(1) of this section shall be effective on January 1 of the first full calendar year for which the unit meets the requirements of paragraph (a) of this section. By December 31 of the first year for which the unit is to be exempt under this section, a statement signed by the designated representative (authorized in accordance with subpart B of this part) or, if no designated representative has been authorized, a certifying official of each owner of the unit shall be submitted to permitting authority otherwise responsible for administering a Phase II Acid Rain permit for the unit. If the Administrator is not the permitting authority, a copy of the statement shall be submitted to the Administrator. The statement, which shall be in a format prescribed by the Administrator, shall identify the unit, state the nameplate capacity of each generator served by the unit and the fuels currently burned or expected to be burned by the unit and their sulfur content by weight, and state that the owners and operators of the unit will comply with paragraph (f) of this section.

(3) After receipt of the statement under paragraph (b)(2) of this section,

the permitting authority shall amend under § 72.83 the operating permit covering the source at which the unit is located, if the source has such a permit, to add the provisions and requirements of the exemption under paragraphs (a), (b)(1), (d), and (f) of this section.

(c)(1) Any new utility unit that meets the requirements of paragraph (a) of this section and that is allocated one or more allowances under subpart B of part 73 of this chapter shall be exempt from the Acid Rain Program, except for the provisions of this section, §§ 72.2 through 72.6, and §§ 72.10 through 72.13, if each of the following requirements are met:

(i) The designated representative (authorized in accordance with subpart B of this part) or, if no designated representative has been authorized, a certifying official of each owner of the unit submits to the permitting authority otherwise responsible for administering a Phase II Acid Rain permit for the unit a statement (in a format prescribed by the Administrator) that:

(A) Identifies the unit and states the nameplate capacity of each generator served by the unit and the fuels currently burned or expected to be burned by the unit and their sulfur content by weight;

(B) States that the owners and operators of the unit will comply with paragraph (f) of this section;

(C) Surrenders allowances equal in number to, and with the same or earlier compliance use date as, all of those allocated to the unit under subpart B of part 73 of this chapter for the first year that the unit is to be exempt under this section and for each subsequent year; and

(D) Surrenders any proceeds for allowances under paragraph (c)(1)(i)(C) or this section withheld from the unit under § 73.10 of this chapter. If the Administrator is not the permitting authority, a copy of the statement shall be submitted to the Administrator.

(ii) The Administrator deducts from the unit's Allowance Tracking System account allowances under paragraph (c)(1)(i)(C) of this section and receives proceeds under paragraph (c)(1)(i)(D) of this section. Within 5 business days of receiving a statement in accordance with paragraph (c)(1)(i) of this section, the Administrator shall either deduct the allowances under paragraph (c)(1)(i)(C) of this section or notify the owners and operators that there are insufficient allowances to make such deductions. Upon completion of such deductions and receipt of such proceeds, the Administrator will close the unit's Allowance Tracking System account and notify the designated

representative (or certifying official) and, if the Administrator is not the permitting authority otherwise responsible for administering a Phase II Acid Rain permit for the unit, the permitting authority.

(2) The exemption under paragraph (c)(1) of this section shall be effective on January 1 of the first full calendar year for which the requirements of paragraphs (a) and (c)(1) of this section are met. After notification by the Administrator under the third sentence of paragraph (c)(1)(ii) of this section, the permitting authority shall amend under § 72.83 the operating permit covering the source at which the unit is located, if the source has such a permit, to add the provisions and requirements of the exemption under paragraphs (a), (c)(1), (d), and (f) of this section.

(d) Compliance with the requirement that fuel burned during the year have an annual average sulfur content of 0.05 percent by weight or less shall be determined as follows using a method of determining sulfur content that provides information with reasonable precision, reliability, accessibility, and timeliness:

(1) For gaseous fuel burned during the year, if natural gas is the only gaseous fuel burned, the requirement is assumed to be met;

(2) For gaseous fuel burned during the year where other gas in addition to or besides natural gas is burned, the requirement is met if the annual average sulfur content is equal to or less than 0.05 percent by weight. The annual average sulfur content, as a percentage by weight, for the gaseous fuel burned shall be calculated as follows:

$$\%S_{\text{annual}} = \frac{\sum_{n=1}^{\text{last}} \%S_n V_n d_n}{\sum_{n=1}^{\text{last}} V_n d_n}$$

Where:

$\%S_{\text{annual}}$ =annual average sulfur content of the fuel burned during the year by the unit, as a percentage by weight;

$\%S_n$ =sulfur content of the nth sample of the fuel delivered during the year to the unit, as a percentage by weight;

V_n =volume of the fuel in a delivery during the year to the unit of which the nth sample is taken, in standard cubic feet; or, for fuel delivered during the year to the unit continuously by pipeline, volume of the fuel delivered starting from when the nth sample of such fuel is taken until the next sample of such fuel is taken, in standard cubic feet;

d_n =density of the nth sample of the fuel delivered during the year to the

unit, in lb per standard cubic foot; and
n=each sample taken of the fuel

delivered during the year to the unit, taken at least once for each delivery; or, for fuel that is delivered during the year to the unit continuously by pipeline, at least once each quarter during which the fuel is delivered.

(3) For nongaseous fuel burned during the year, the requirement is met if the annual average sulfur content is equal to or less than 0.05 percent by weight. The annual average sulfur content, as a percentage by weight, shall be calculated using the equation in paragraph (d)(2) of this section. In lieu of the factor, volume times density ($V_n d_n$), in the equation, the factor, mass (M_n), may be used, where M_n is: mass of the nongaseous fuel in a delivery during the year to the unit of which the nth sample is taken, in lb; or, for fuel delivered during the year to the unit continuously by pipeline, mass of the nongaseous fuel delivered starting from when the nth sample of such fuel is taken until the next sample of such fuel is taken, in lb.

(e)(1) A utility unit that was issued a written exemption under this section and that meets the requirements of paragraph (a) of this section shall be exempt from the Acid Rain Program, except for the provisions of this section, §§ 72.2 through 72.6, and §§ 72.10 through 72.13 and shall be subject to the requirements of paragraphs (a), (d), (e)(2), and (f) of this section in lieu of the requirements set forth in the written exemption. The permitting authority shall amend under § 72.83 the operating permit covering the source at which the unit is located, if the source has such a permit, to add the provisions and requirements of the exemption under this paragraph (e)(1) and paragraphs (a), (d), (e)(2), and (f) of this section.

(2) If a utility unit under paragraph (e)(1) of this section is allocated one or more allowances under subpart B of part 73 of this chapter, the designated representative (authorized in accordance with subpart B of this part) or, if no designated representative has been authorized, a certifying official of each owner of the unit shall submit to the permitting authority that issued the written exemption a statement (in a format prescribed by the Administrator) meeting the requirements of paragraph (c)(1)(i)(C) and (D) of this section. The statement shall be submitted by June 31, 1998 and, if the Administrator is not the permitting authority, a copy shall be submitted to the Administrator.

(f) Special Provisions. (1) The owners and operators and, to the extent applicable, the designated

representative of a unit exempt under this section shall:

(i) Comply with the requirements of paragraph (a) of this section for all periods for which the unit is exempt under this section; and

(ii) Comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(2) For any period for which a unit is exempt under this section, the unit is not an affected unit under the Acid Rain Program and parts 70 and 71 of this chapter and is not eligible to be an opt-in source under part 74 of this chapter. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under parts 70 and 71 of this chapter.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit records demonstrating that the requirements of paragraph (a) of this section are met. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority.

(i) Such records shall include, for each delivery of fuel to the unit or for fuel delivered to the unit continuously by pipeline, the type of fuel, the sulfur content, and the sulfur content of each sample taken.

(ii) The owners and operators bear the burden of proof that the requirements of paragraph (a) of this section are met.

(4) Loss of exemption. (i) On the earliest of the following dates, a unit exempt under paragraphs (b), (c), or (e) of this section shall lose its exemption and become an affected unit under the Acid Rain Program and parts 70 and 71 of this chapter:

(A) The date on which the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe;

(B) The date on which the unit burns any coal or coal-derived fuel except for coal-derived gaseous fuel with a total sulfur content no greater than natural gas; or

(C) January 1 of the year following the year in which the annual average sulfur content for gaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under paragraph (d) of this section) or for nongaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under paragraph (d) of this section).

(ii) Notwithstanding § 72.30(b) and (c), the designated representative for a unit that loses its exemption under this section shall submit a complete Acid Rain permit application on the later of January 1, 1998 or 60 days after the first date on which the unit is no longer exempt.

(iii) For the purpose of applying monitoring requirements under part 75 of this chapter, a unit that loses its exemption under this section shall be treated as a new unit that commenced commercial operation on the first date on which the unit is no longer exempt.

8. Section 72.8 is revised to read as follows:

§ 72.8 Retired units exemption.

(a) This section applies to any affected unit (except for an opt-in source) that is permanently retired.

(b)(1) Any affected unit (except for an opt-in source) that is permanently retired shall be exempt from the Acid Rain Program, except for the provisions of this section, §§ 72.2 through 72.6, §§ 72.10 through 72.13, and subpart B of part 73 of this chapter.

(2) The exemption under paragraph (b)(1) of this section shall become effective on January 1 of the first full calendar year during which that the unit is permanently retired. By December 31 of the first year that the unit is to be exempt under this section, the designated representative (authorized in accordance with subpart B of this part), or, if no designated representative has been authorized, a certifying official of each owner of the unit shall submit a statement to the permitting authority otherwise responsible for administering a Phase II Acid Rain permit for the unit. If the Administrator is not the permitting authority, a copy of the statement shall be submitted to the Administrator. The statement shall state (in a format prescribed by the Administrator) that the unit is permanently retired and will comply with the requirements of paragraph (d) of this section.

(3) After receipt of the notice under paragraph (b)(2) of this section, the permitting authority shall amend under § 72.83 the operating permit covering the source at which the unit is located, if the source has such a permit, to add the provisions and requirements of the exemption under paragraphs (b)(1) and (d) of this section.

(c) A unit that was issued a written exemption under this section and that is permanently retired shall be exempt from the Acid Rain Program, except for the provisions of this section, §§ 72.2 through 72.6, §§ 72.10 through 72.13, and subpart B of part 73 of this chapter,

and shall be subject to the requirements of paragraph (d) of this section in lieu of the requirements set forth in the written exemption. The permitting authority shall amend under § 72.83 the operating permit covering the source at which the unit is located, if the source has such a permit, to add the provisions and requirements of the exemption under this paragraph (c) and paragraph (d) of this section.

(d) Special Provisions. (1) A unit exempt under this section shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with subpart B of part 73 of this chapter. If the unit is a Phase I unit, for each calendar year in Phase I, the designated representative of the unit shall submit a Phase I permit application in accordance with subparts C and D of this part 72 and an annual certification report in accordance with §§ 72.90 through 72.92 and is subject to §§ 72.95 and 72.96.

(2) A unit exempt under this section shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain permit application under § 72.31 for the unit not less than 24 months prior to the later of January 1, 2000 or the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under this section shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under this section, the unit is not an affected unit under the Acid Rain Program and parts 70 and 71 of this chapter and is not eligible to be an opt-in source under part 74 of this chapter. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under parts 70 and 71 of this chapter.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) Loss of exemption. (i) On the earlier of the following dates, a unit exempt under paragraph (b) or (c) of this section shall lose its exemption and become an affected unit under the Acid Rain Program and parts 70 and 71 of this chapter:

(A) The date on which the designated representative submits an Acid Rain permit application under paragraph (d)(2) of this section; or

(B) The date on which the designated representative is required under paragraph (d)(2) of this section to submit an Acid Rain permit application.

(ii) For the purpose of applying monitoring requirements under part 75 of this chapter, a unit that loses its exemption under this section shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

§ 72.9 [Amended]

9. Section 72.9 is amended by:

a. Removing from paragraphs (b)(1) and (2) the words “and section 407 of the Act and regulations implementing section 407 of the Act”;

b. Removing from paragraph (b)(3) the words “and regulations implementing section 407 of the Act”;

c. Removing from paragraph (c)(6) the words “the written exemption under §§ 72.7 and 72.8” and adding in their place, the words “an exemption under §§ 72.7, 72.8, or 72.14”;

d. Removing from paragraph (f)(1)(ii) the punctuation “.” and adding in its place the words “; provided that to the extent that part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.”;

e. Removing from paragraph (g)(1) the words “a written exemption under § 72.7 or § 72.8” and adding, in their place, the words “an exemption under §§ 72.7, 72.8, or 72.14”;

f. Removing from paragraph (g)(6) the words “part 76 of this chapter” and adding, in their place, the words “§ 76.11 of this chapter; and

g. Removing from paragraph (h) introductory text the words “a written exemption under §§ 72.7 or 72.8” and adding, in their place, the words “an exemption under §§ 72.7, 72.8, or 72.14”.

§ 72.13 [Amended]

10. Section 72.13 is amended by:

a. Removing paragraphs (a)(1), (a)(5), (a)(6), (a)(7), (a)(9), and (a)(10);

b. Redesignating paragraph (a)(2) as paragraph (a)(1);

c. Redesignating paragraph (a)(3) as paragraph (a)(2);

d. Redesignating paragraph (a)(4) as paragraph (a)(3), and

e. Redesignating paragraph (a)(8) as paragraph (a)(4).

11. Section 72.14 is added to read as follows:

§ 72.14 Industrial utility-units exemption.

(a) *Applicability.* This section applies to any non-cogeneration, utility unit that has not previously lost an exemption under paragraph (d)(4) of this section and that meets the following criteria:

(1) Starting on the date of the signing of the interconnection agreement under paragraph (a)(2) of this section and thereafter, there has been no owner or operator of the unit, division or subsidiary or affiliate or parent company of an owner or operator of the unit, or combination thereof whose principal business is the sale, transmission, or distribution of electricity or that is a public utility under the jurisdiction of a State or local utility regulatory authority;

(2) On or before March 23, 1993, the owners or operators of the unit entered into an interconnection agreement and any related power purchase agreement with a person whose principal business is the sale, transmission, or distribution of electricity or that is a public utility under the jurisdiction of a State or local utility regulatory authority, requiring the generator or generators served by the unit to produce electricity for sale only for incidental electricity sales to such person;

(3) The unit served or serves one or more generators that, in 1985 or any year thereafter, actually produced electricity for sale only for incidental electricity sales required under the interconnection agreement and any related power purchase agreement under paragraph (a)(2) of this section or a successor agreement under paragraph (d)(4)(ii) of this section; and

(4) Incidental electricity sales, under this section, are total annual sales of electricity produced by a generator that do not exceed 10 percent of the nameplate capacity of that generator times 8,760 hours per year and do not exceed 10 percent of the actual annual electric output of that generator.

(b) *Petition for exemption.* The designated representative (authorized in accordance with subpart B of this part) of a unit under paragraph (a) of this section may submit to the permitting authority otherwise responsible for administering a Phase II Acid Rain permit for the unit a complete petition for an exemption for the unit from the requirements of the Acid Rain Program, except for the provisions of this section, §§ 72.2 through 72.6, and §§ 72.10 through 72.13. If the Administrator is

not the permitting authority, a copy of the petition shall be submitted to the Administrator. A complete petition shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit;
(2) A statement that the unit is not a cogeneration unit;
(3) A list of the current owners and operators of the unit and any other owners and operators of the unit, starting on the date of the signing of the interconnection agreement under paragraph (a)(2) of this section, and a statement that, starting on that date, there has been no owner or operator of the unit, division or subsidiary or affiliate or parent company of an owner or operator of the unit, or combination thereof whose principal business is the sale, transmission, or distribution of electricity or that is a public utility under the jurisdiction of a State or local utility regulatory authority;

(4) A summary of the terms of the interconnection agreement and any related power purchase agreement under paragraph (a)(2) of this section and any successor agreement under paragraph (d)(4)(ii) of this section, including the date on which the agreement was signed, the amount of electricity that may be required to be produced for sale by each generator served by the unit, and the provisions for expiration or termination of the agreement;

(5) A copy of the interconnection agreement and any related power purchase agreement under paragraph (a)(2) of this section and any successor agreement under paragraph (d)(4)(ii) of this section;

(6) The nameplate capacity of each generator served by the unit;

(7) For each year starting in 1985, the actual annual electrical output of each generator served by the unit, the total amount of electricity produced for sales to any customer by each generator, and the total amount of electricity produced and sold as required by the interconnection agreement and any related power purchase agreement under paragraph (a)(2) of this section or any successor agreement under paragraph (d)(4)(ii) of this section;

(8) A statement that each generator served by the unit actually produced electricity for sale only for incidental electricity sales (in accordance with paragraph (a)(4) of this section) required under the interconnection agreement and any related power purchase agreement under paragraph (a)(2) of this section or any successor agreement under paragraph (d)(4)(ii) of this section; and

(9) The special provisions of paragraph (d) of this section.

(c) *Permitting Authority's Action.* (1) (i) For any unit meeting the requirements of paragraphs (a) and (b) of this section, the permitting authority shall issue an exemption from the requirements of the Acid Rain Program, except for the provisions of this section, §§ 72.2 through 72.6 and §§ 72.10 through 72.13.

(ii) If a petition for exemption is submitted for a unit but the designated representative fails to demonstrate that the requirements of paragraph (a) of this section are met, the permitting authority shall deny an exemption under this section.

(2) In issuing or denying an exemption under paragraph (c)(1) of this section, the permitting authority shall treat the petition for exemption as a permit application and apply the procedures used for issuing or denying draft, proposed (if the Administrator is not the permitting authority otherwise responsible for administering a Phase II Acid Rain permit for the unit), and final Acid Rain permits.

(3) An exemption issued under paragraph (c)(1)(i) of this section shall become effective on January 1 of the first full year the unit meets the requirements of paragraph (a) of this section.

(4) An exemption issued under paragraph (c)(1)(i) of this section shall be effective until the date on which the unit loses the exemption under paragraph (d)(4) of this section.

(5) After issuance of the exemption under paragraphs (c)(1) and (2) of this section, the permitting authority shall amend under § 72.83 the operating permit covering the source at which the unit is located, if the source has such a permit, to add the provisions and requirements of the exemption under paragraphs (c)(1)(i) and (d) of this section.

(d) *Special Provisions.* (1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under this section shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(2) For any period for which a unit is exempt under this section, the unit is not an affected unit under the Acid Rain Program and parts 70 and 71 of this chapter and is not eligible to be an opt-in source under part 74 of this chapter. As an unaffected unit, the unit shall continue to be subject to any other

applicable requirements under parts 70 and 71 of this chapter.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit records demonstrating that the requirements of paragraph (a) of this section are met. The owners and operators bear the burden of proof that the requirements of this section are met. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. Such records shall include the following information:

(i) A copy of the interconnection agreement and any related power purchase agreement under paragraph (a)(2) of this section and any successor agreement under paragraph (d)(4)(ii) of this section;

(ii) The nameplate capacity of each generator served by the unit; and

(iii) For each year starting in 1985, the actual annual electrical output of each generator served by the unit, the total amount of electricity produced for sales to any customer by each generator, and the total amount of electricity produced and sold as required by the interconnection agreement and any related power purchase agreement under paragraph (a)(2) of this section or any successor agreement under paragraph (d)(4)(ii) of this section.

(4) *Loss of exemption.* (i) On the earliest of the following dates, a unit exempt under this section shall lose its exemption and become an affected unit under the Acid Rain Program and parts 70 and 71 of this chapter:

(A) The first date on which there is an owner or operator of the unit, division or subsidiary or affiliate or parent company of an owner or operator of the unit, or combination thereof, whose principal business is the sale, transmission, or distribution of electricity or that is a public utility under the jurisdiction of a State or local utility regulatory authority.

(B) If any generator served by the unit actually produces any electricity for sale other than for sale to the person specified as the purchaser in the interconnection agreement or any related power purchase agreement under paragraph (a)(2) of this section or a successor agreement under paragraph (d)(4)(ii) of this section, then the day after the date on which such electricity is sold.

(C) If any generator served by the unit actually produces any electricity for sale to the person specified as the purchaser in the interconnection agreement or any

related power purchase agreement under paragraph (a)(2) of this section or a successor agreement under paragraph (d)(4)(ii) of this section where such sale is not required under that interconnection agreement or related power purchase agreement or successor agreement or where such sale will result in total sales for a calendar year exceeding 10 percent of the nameplate capacity of that generator times 8,769 hours per year, then the day after the date on which such sale is made.

(D) If any generator served by the unit actually produces any electricity for sale to the person specified as the purchaser in the interconnection agreement or related power purchase agreement under paragraph (a)(2) of this section or a successor agreement under paragraph (d)(4)(ii) of this section where such sale results in total sales for a calendar year exceeding 10 percent of the actual electric output of the generator for that year, then January 1 of the year after such year.

(E) If the interconnection agreement or related power purchase agreement under paragraph (a)(2) of this section expires or is terminated, no successor agreement under paragraph (d)(4)(ii) of this section is in effect, and any generator served by the unit actually produces any electricity for sale, then the day after the date on which such electricity is sold.

(ii) A "successor agreement" is an agreement that:

(A) Modifies, replaces or supersedes the interconnection agreement or related power purchase agreement under paragraph (a)(2) of this section;

(B) Is between the owners and operators of the unit and a person that is contractually obligated to sell electricity to the owners and operators of the unit and either whose principal business is the sale, transmission, or distribution of electricity or that is a public utility under the jurisdiction of a State or local utility regulatory authority; and

(C) Requires the generator served by the unit to produce electricity for sale to the person under paragraph (d)(4)(ii)(B) of this section and only for incidental electricity sales, such that the total amount of electricity that such generator is required to produce for sale under the interconnection agreement or related power purchase agreement (to the extent they are still in effect) and the successor agreement shall not exceed the total amount of electricity that such generator was required to produce for sale under the interconnection agreement or related power purchase agreement under paragraph (a)(2) of this section.

(iii) Notwithstanding § 72.30(b) and (c), the designated representative for a unit that loses its exemption under this section shall submit a complete Acid Rain permit application on the later of January 1, 1998 or 60 days after the first date on which the unit is no longer exempt.

(iv) For the purpose of applying monitoring requirements under part 75 of this chapter, a unit that loses its exemption under this section shall be treated as a new unit that commenced commercial operation on the first date on which the unit is no longer exempt.

12. Section 72.22 is amended by adding paragraph (e) to read as follows:

§ 72.22 Alternate designated representative.

* * * * *

(e)(1) Notwithstanding paragraph (a) of this section, the certification of representation may designate two alternate designated representatives for a unit if:

(i) The unit and at least one other unit, which are located in two or more of the contiguous 48 States or the District of Columbia, each have a utility system that is a subsidiary of the same company; and

(ii) The designated representative for the units under paragraph (e)(1)(i) of this section submits a NO_x averaging plan under § 76.11 of this chapter that covers such units and is approved by the permitting authority, *provided* that the approved plan remains in effect.

(2) Except in this paragraph (e), whenever the term "alternate designated representative" is used under the Acid Rain Program, the term shall be construed to include either of the alternate designated representatives authorized under this paragraph (e). Except in this section, § 72.23, and § 72.24, whenever the term "designated representative" is used under the Acid Rain Program, the term shall be construed to include either of the alternate designated representatives authorized under this paragraph (e).

13. Section 72.24 is amended by revising paragraphs (a)(3), (5), (10), and (11) to read as follows:

§ 72.24 Certificate of representation.

(a) * * *

(3) A list of the owners and operators of the affected source and of each affected unit at the source.

* * * * *

(5) The following statement: "I certify that I have given notice of the agreement, selecting me as the 'designated representative' for the affected source and each affected unit at the source identified in this certificate

of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice."

* * * * *

(10) If an alternate designated representative is authorized in the certificate of representation, the following statement: "The agreement by which I was selected as the alternate designated representative includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative."

(11) The signature of the designated representative and any alternate designated representative who is authorized in the certificate of representation and the date signed.

* * * * *

§ 72.25 [Amended]

14. Section 72.25 is amended by removing from paragraph (a) the words "submitted to" and adding, in their place, the words "received by".

15. Section 72.30 is amended by removing paragraph (b)(3) and adding paragraph (e) to read as follows:

§ 72.30 Requirement to apply.

* * * * *

(e) Where two or more affected units are located at a source, the permitting authority may, in its sole discretion, allow the designated representative of the source to submit, under paragraph (a) or (c) of this section, two or more Acid Rain permit applications covering the units at the source, *provided* that each affected unit is covered by one and only one such application.

§ 72.31 [Amended]

16. Section 72.31 is amended by removing from paragraph (b) the words "Phase II unit" and adding in their place the words "affected unit (except for an opt-in source)".

17. Section 72.32 is amended by revising paragraphs (b) and (c) and adding paragraph (d) to read as follows:

§ 72.32 Permit application shield and binding effect of permit application.

* * * * *

(b) Prior to the date on which an Acid Rain permit is issued or denied, an affected unit governed by and operated in accordance with the terms and requirements of a timely and complete Acid Rain permit application shall be deemed to be operating in compliance with the Acid Rain Program.

(c) A complete Acid Rain permit application shall be binding on the

owners and operators and the designated representative of the affected source and the affected units covered by the permit application and shall be enforceable as an Acid Rain permit from the date of submission of the permit application until the issuance or denial of an Acid Rain permit covering the units.

(d) If agency action concerning a permit is appealed under part 78 of this chapter, issuance or denial of the permit shall occur when the Administrator takes final agency action subject to judicial review.

18. Section 72.33 is amended by adding a sentence to the end of paragraph (b)(3) to read as follows:

§ 72.33 Identification of dispatch system.

* * * * *

(b) * * *

(3) * * * A designated representative may request, and the Administrator may grant at his or her discretion, an exemption allowing the submission of an identification of dispatch system after the otherwise applicable deadline for such submission.

* * * * *

§ 72.40 [Amended]

19. Section 72.40 is amended by:

a. Removing from paragraph (a)(2) the words "applicable limitation established by regulations implementing section 407 of the Act" and adding, in their place, the words "applicable emission limitation under §§ 76.5, 76.6, or 76.7 of this chapter";

b. Removing from paragraph (a)(2) the words "section 407 of the Act and the regulations implementing section 407" and adding, in their place, the words "part 76 of this chapter";

c. Removing from paragraph (b)(1) the words "an NO_x averaging plan contained in part 76 of this chapter" and adding, in their place, the words "a NO_x averaging plan under § 76.11 of this chapter"; and

d. Removing from paragraphs (c) introductory text, (c)(1), and (d)(1) the words "regulations implementing section 407 of the Act" and adding, in their place, the words "part 76 of this chapter".

§ 72.41 [Amended]

20. Section 72.41 is amended by: removing from paragraph (b)(3) the words "90 days" and adding, in their place, the words "6 months (or 90 days if submitted in accordance with § 72.82)"; and removing from paragraph (e)(1)(ii) the words "section 407 of the Act and regulations implementing section 407 of the Act" and adding, in their place, the words "part 76 of this chapter".

§ 72.43 [Amended]

21. Section 72.43 is amended by: removing from paragraph (b)(2)(iii)(B) the words "under § 72.92" and adding, in their place, the words "under § 72.91(b)"; removing from paragraph (b)(4) the words "90 days" and adding, in their place, the words "6 months (or 90 days if submitted in accordance with § 72.82 or § 72.83)"; and removing from paragraph (f)(1)(i) the words "section 407 of the Act and regulations implementing section 407 of the Act" and adding, in their place, the words "part 76 of this chapter".

§ 72.44 [Amended]

22. Section 72.44 is amended by:

a. Removing from paragraphs (g)(1)(i) and (2) the words "proposed permit revision" and adding, in their place, the words "requested permit modification";

b. Adding between the first and second sentences of paragraphs (g)(1)(i) and (2) the words "If the Administrator is not the permitting authority, a copy of the requested permit modification shall be submitted to the Administrator.";

c. Removing from paragraph (g)(2)(iii) the words "December 21" and adding, in their place, the words "December 31"; and

d. Removing from paragraph (h)(1)(ii) the words "section 407 of the Act and regulations implementing section 407 of the Act" and adding, in their place, the words "part 76 of this chapter".

§ 72.51 [Amended]

23. Section 72.51 is amended by: removing the words "parts 73, 75, 77, and 78 of this chapter, and regulations implementing section 407 of the Act" and adding, in their place, the words "parts 73, 74, 75, 76, 77, and 78 of this chapter"; and removing the words "of this part".

24. Section 72.60 is revised to read as follows:

§ 72.60 General.

(a) *Scope.* This subpart and parts 74, 76, and 78 of this chapter contain the procedures for federal issuance of Acid Rain permits for Phase I of the Acid Rain Program and Phase II for sources for which the Administrator is the permitting authority under § 72.74.

(1) Notwithstanding the provisions of part 71 of this chapter, the provisions of subparts C, D, E, F, and H of this part and of parts 74, 76, and 78 of this chapter shall govern the following requirements for Acid Rain permit applications and permits: submission, content, and effect of permit applications; content and requirements of compliance plans and compliance

options; content of permits and permit shield; procedures for determining completeness of permit applications; issuance of draft permits; administrative record; public notice and comment and public hearings on draft permits; response to comments on draft permits; issuance and effectiveness of permits; permit revisions; and administrative appeal procedures. The provisions of part 71 of this chapter concerning Indian tribes, delegation of a part 71 program, affected State review of draft permits, and public petitions to reopen a permit for cause shall apply to Acid Rain permit applications and permits.

(2) The procedures in this subpart do not apply to the issuance of Acid Rain permits by State permitting authorities with operating permit programs approved under part 70 of this chapter, except as expressly provided in subpart G of this part.

(b) *Permit Decision Deadlines.* Except as provided in § 72.74(c)(1)(i), the Administrator will issue or deny an Acid Rain permit under § 72.69(a) within 6 months of receipt of a complete Acid Rain permit application submitted for a unit, in accordance with § 72.21, at the U.S. EPA Regional Office for the Region in which the source is located.

(c) *Use of Direct Final Procedures.* The Administrator may, in his or her discretion, issue, as single document, a draft Acid Rain permit in accordance with § 72.62 and an Acid Rain permit in final form and may provide public notice of the opportunity for public comment on the draft Acid Rain permit in accordance with § 72.65. The Administrator may provide that, if no significant, adverse comment on the draft Acid Rain permit is timely submitted, the Acid Rain permit will be deemed to be issued on a specified date without further notice and, if such significant, adverse comment is timely submitted, an Acid Rain permit or denial of an Acid Rain permit will be issued in accordance with § 72.69. Any notice provided under this paragraph (c) will include a description of the procedure in the prior sentence.

25. Section 72.61 is amended by revising paragraphs (a) and (b)(2)(i) and adding paragraph (b)(3) to read as follows:

§ 72.61 Completeness.

(a) *Determination of Completeness.* The Administrator will determine whether the Acid Rain permit application is complete within 60 days of receipt by the U.S. EPA Regional Office for the Region in which the source is located. The permit application shall be deemed to be complete if the Administrator fails to

notify the designated representative to the contrary within 60 days of receipt.

(b) * * *

(2)(i) Within a reasonable period determined by the Administrator, the designated representative shall submit the information required under paragraph (b)(1) of this section.

* * * * *

(3) Any designated representative who fails to submit any relevant information or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or corrected information to the Administrator.

26. Section 72.65 is amended by revising paragraphs (b)(1)(ii), (b)(1)(iii), and (b)(2) and by removing paragraph (b)(1)(iv) to read as follows:

§ 72.65 Public notice of opportunities of public comment.

* * * * *

(b) * * *

(1) * * *

(ii) The air pollution control agencies of affected States; and

(iii) Any interested person.

(2) Giving notice by publication in the **Federal Register** and in a newspaper of general circulation in the area where the source covered by the Acid Rain permit application is located or in a State publication designed to give general public notice. Notwithstanding the prior sentence, if a draft permit requires the affected units at a source to comply with § 72.9(c)(1) and to meet any applicable emission limitation for NO_x under §§ 76.5, 76.6, 76.7, 76.8, or 76.11 of this chapter and does not include for any unit a compliance option under § 72.44, part 74 of this chapter, or § 76.10 of this chapter, the Administrator may, in his or her discretion, provide notice of the draft permit by **Federal Register** publication and may omit notice by newspaper or State publication.

* * * * *

27. Section 72.69 is amending by revising paragraph (a) to read as follows:

§ 72.69 Issuance and effective date of Acid Rain permits.

(a) After the close of the public comment period, the Administrator will issue or deny an Acid Rain permit. The Administrator will serve a copy of any Acid Rain permit and the response to comments on the designated representative for the source covered by the issuance or denial and serve written notice of the issuance or denial on the air pollution control agencies of affected States and any interested person. The

Administrator will also give notice in the **Federal Register**.

* * * * *

28. Section 72.70 is revised to read as follows:

§ 72.70 Relationship to title V operating permit program.

(a) *Scope.* This subpart sets forth criteria for approval of State operating permit programs and acceptance of State Acid Rain programs, the procedure for including State Acid Rain programs in a title V operating permit program, and the requirements with which State permitting authorities with accepted programs shall comply, and with which the Administrator will comply in the absence of an accepted State program, to issue Phase II Acid Rain permits.

(b) *Relationship to operating permit program.* Each State permitting authority with an affected source shall act in accordance with this part and parts 70, 74, 76, and 78 of this chapter for the purpose of incorporating Acid Rain Program requirements into each affected source's operating permit or for issuing exemptions under § 72.14. To the extent that this part or part 74, 76, or 78 of this chapter is inconsistent with the requirements of part 70 of this chapter, this part and parts 74, 76, and 78 of this chapter shall take precedence and shall govern the issuance, denial, revision, reopening, renewal, and appeal of the Acid Rain portion of an operating permit.

29. Section 72.71 is revised to read as follows:

§ 72.71 Acceptance of State Acid Rain programs—general.

(a) Each State shall submit, to the Administrator for review and acceptance, a State Acid Rain program meeting the requirements of §§ 72.72 and 72.73.

(b) The Administrator will review each State Acid Rain program or portion of a State Acid Rain program and accept, by notice in the **Federal Register**, all or a portion of such program to the extent that it meets the requirements of §§ 72.72 and 72.73. At his or her discretion, the Administrator may accept, with conditions and by notice in the **Federal Register**, all or a portion of such program despite the failure to meet requirements of §§ 72.72 and 72.73. On the later of the date of publication of such notice in the **Federal Register** or the date on which the State operating permit program is approved under part 70 of this chapter, the State Acid Rain program accepted by the Administrator will become a portion of the approved State operating permit program. Before accepting or

rejecting all or a portion of a State Acid Rain Program, the Administrator will provide notice and opportunity for public comment on such acceptance or rejection.

(c)(1) Except as provided in paragraph (c)(2) of this section, the Administrator will issue all Acid Rain permits for Phase I. The Administrator reserves the right to delegate the remaining administration and enforcement of Acid Rain permits for Phase I to approved State operating permit programs.

(2) The State permitting authority will issue an opt-in permit for a combustion or process source subject to its jurisdiction if, on the date on which the combustion or process source submits an opt-in permit application, the State permitting authority has opt-in regulations accepted under paragraph (b) of this section and an approved operating permits program under part 70 of this chapter.

30. Section 72.72 is amended by:

a. Removing paragraphs (b)(1)(i)(C), (b)(1)(vii), (b)(1)(viii), (b)(1)(xi), (b)(1)(xiii), (b)(5)(vii), (b)(7), and (b)(8);

b. Removing the last sentence of paragraph (b)(5)(v);

c. Redesignating paragraphs (b)(1)(ix) and (x) as paragraphs (b)(1)(vii) and (viii) respectively;

d. Redesignating paragraph (b)(1)(xii) as paragraph (b)(1)(ix);

e. Redesignating paragraph (b)(1)(xiv) as paragraph (b)(1)(x);

f. Removing and reserving paragraph (b)(5)(ii); and

g. Revising the heading, the introductory text, and paragraphs (b) introductory text, (b)(1)(ii), (b)(1)(iii), (b)(1)(iv), (b)(1)(v), (b)(1)(vi), the first sentence of (b)(5)(i), (b)(5)(vi), and (b)(6) to read as follows:

§ 72.72 Criteria for State operating permit program.

A State operating permit program (including a State Acid Rain program) shall meet the following criteria. Any aspect of a State operating permits program or any implementation of a State operating permit program that fails to meet these criteria shall be grounds for nonacceptance or withdrawal of all or part of the Acid Rain portion of an approved State operating permit program by the Administrator or for disapproval or withdrawal of approval of the State operating permit program by the Administrator.

* * * * *

(b) The State operating permit program shall require the following provisions, which are adopted to the extent that this paragraph (b) is incorporated by reference or is

otherwise included in the State operating permit program.

(1) * * *

(ii) *Draft Permit.* (A) The State permitting authority shall prepare the draft Acid Rain permit in accordance with subpart E of this part and part 76 of this chapter or, for a combustion or process source, with subpart B of part 74 of this chapter, or deny a draft Acid Rain permit.

(B) Prior to issuance of a draft permit for a combustion or process source, the State permitting authority shall provide the designated representative of a combustion or process source an opportunity to confirm its intention to opt-in, in accordance with § 74.14 of this chapter.

(iii) *Public Notice and Comment Period.* Public notice of the issuance or denial of the draft Acid Rain permit and the opportunity to comment and request a public hearing shall be given by publication in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice. Notwithstanding the prior sentence, if a draft permit requires the affected units at a source to comply with § 72.9(c)(1) and to meet any applicable emission limitation for NO_x under §§ 76.5, 76.6, 76.7, 76.8, or 76.11 of this chapter and does not include for any unit a compliance option under § 72.44, part 74 of this chapter, or § 76.10 of this chapter, the State permitting authority may, in its discretion, provide notice by serving notice on persons entitled to receive a written notice and may omit notice by newspaper or State publication.

(iv) *Proposed permit.* The State permitting authority shall incorporate all changes necessary and issue a proposed Acid Rain permit in accordance with subpart E of this part and part 76 of this chapter or, for a combustion or process source, with subpart B of part 74 of this chapter, or deny a proposed Acid Rain permit.

(v) *Direct proposed procedures.* The State permitting authority may, in its discretion, issue, as a single document, a draft Acid Rain permit in accordance with paragraph (b)(1)(ii) of this section and a proposed Acid Rain permit and may provide public notice of the opportunity for public comment on the draft Acid Rain permit in accordance with paragraph (b)(1)(iii) of this section. The State permitting authority may provide that, if no significant, adverse comment on the draft Acid Rain permit is timely submitted, the proposed Acid Rain permit will be deemed to be issued on a specified date without further notice and, if such significant, adverse

comment is timely submitted, a proposed Acid Rain permit or denial of a proposed Acid Rain permit will be issued in accordance with paragraph (b)(1)(iv) of this section. Any notice provided under this paragraph (b)(1)(v) shall include a description of the procedure in the prior sentence.

(vi) *Acid Rain Permit Issuance.* Following the Administrator's review of the proposed Acid Rain permit, the State permitting authority shall or, under part 70 of this chapter, the Administrator will, incorporate any required changes and issue or deny the Acid Rain permit in accordance with subpart E of this part and part 76 of this chapter or, for a combustion or process source, with subpart B of part 74 of this chapter.

* * * * *

(5) * * * (i) Appeals of the Acid Rain portion of an operating permit issued by the State permitting authority that do not challenge or involve decisions or actions of the Administrator under this part or part 73, 74, 75, 76, 77, or 78 of this chapter shall be conducted according to procedures established by the State in accordance with part 70 of this chapter. * * *

* * * * *

(vi) A failure of the State permitting authority to issue an Acid Rain permit in accordance with § 72.73(b)(1) or, with regard to combustion or process sources, § 74.14(b)(6) of this chapter shall be ground for filing an appeal.

(6) *Industrial Utility-Units Exemption.* The State permitting authority shall act in accordance with § 72.14 on any petition for exemption from requirements of the Acid Rain Program.

31. Section 72.73 is revised to read as follows:

§ 72.73 State issuance of Phase II permits.

(a) *State Permit Issuance.* (1) A State that is authorized to administer and enforce an operating permit program under part 70 of this chapter and that has a State Acid Rain program accepted by the Administrator under § 72.71 shall be responsible for administering and enforcing Acid Rain permits effective in Phase II for all affected sources:

(i) That are located in the geographic area covered by the operating permits program; and

(ii) To the extent that the accepted State Acid Rain program is applicable.

(2) In administering and enforcing Acid Rain permits, the State permitting authority shall comply with the procedures for issuance, revision, renewal, and appeal of Acid Rain permits under this subpart.

(b) *Permit Issuance Deadline.* (1) A State, to the extent that it is responsible

under paragraph (a) of this section as of December 31, 1997 (or such later date as the Administrator may establish) for administering and enforcing Acid Rain permits, shall:

(i) On or before December 31, 1997, issue an Acid Rain permit for Phase II covering the affected units (other than opt-in sources) at each source in the geographic area for which the program is approved; *provided* that the designated representative of the source submitted a timely and complete Acid Rain permit application in accordance with § 72.21.

(ii) On or before January 1, 1999, for each unit subject to an Acid Rain NO_x emissions limitation, amend the Acid Rain permit under § 72.83 and add any NO_x early election plan that was approved by the Administrator under § 76.8 of this chapter and has not been terminated and reopen the Acid Rain permit and add any other Acid Rain Program nitrogen oxides requirements; *provided* that the designated representative of the affected source submitted a timely and complete Acid Rain permit application for nitrogen oxides in accordance with § 72.21.

(2) Each Acid Rain permit issued in accordance with this section shall have a term of 5 years commencing on its effective date; *provided* that, at the discretion of the permitting authority, the first Acid Rain permit for Phase II issued to a source may have a term of less than 5 years where necessary to coordinate the term of such permit with the term of an operating permit to be issued to the source under a State operating permit program. Each Acid Rain permit issued in accordance with paragraph (b)(1) of this section shall take effect by the later of January 1, 2000, or, where the permit governs a unit under § 72.6(a)(3) of this part, the deadline for monitor certification under part 75 of this chapter.

32. Section 72.74 is revised to read as follows:

§ 72.74 Federal issuance of Phase II permits.

(a)(1) The Administrator will be responsible for administering and enforcing Acid Rain permits for Phase II for any affected sources to the extent that a State permitting authority is not responsible, as of January 1, 1997 or such later date as the Administrator may establish, for administering and enforcing Acid Rain permits for such sources under § 72.73(a).

(2) After and to the extent the State permitting authority becomes responsible for administering and enforcing Acid Rain permits under § 72.73(a), the Administrator will

suspend federal administration of Acid Rain permits for Phase II for sources and units to the extent that they are subject to the accepted State Acid Rain program, except as provided in paragraph (b)(4) of this section.

(b)(1) The Administrator will administer and enforce Acid Rain permits effective in Phase II for sources and units during any period that the Administrator is administering and enforcing an operating permit program under part 71 of this chapter for the geographic area in which the sources and units are located.

(2) The Administrator will administer and enforce Acid Rain permits effective in Phase II for sources and units otherwise subject to a State Acid Rain program under § 72.73(a) if:

(i) The Administrator determines that the State permitting authority is not adequately administering or enforcing all or a portion of the State Acid Rain program, notifies the State permitting authority of such determination and the reasons therefore, and publishes such notice in the **Federal Register**;

(ii) The State permitting authority fails either to correct the deficiencies within a reasonable period (established by the Administrator in the notice under paragraph (b)(2)(i) of this section) after issuance of the notice or to take significant action to assure adequate administration and enforcement of the program within a reasonable period (established by the Administrator in the notice) after issuance of the notice; and

(iii) The Administrator publishes in the **Federal Register** a notice that he or she will administer and enforce Acid Rain permits effective in Phase II for sources and units subject to the State Acid Rain program or a portion of the program. The effective date of such notice shall be a reasonable period (established by the Administrator in the notice) after the issuance of the notice.

(3) When the Administrator administers and enforces Acid Rain permits under paragraph (b)(1) or (b)(2) of this section, the Administrator will administer and enforce each Acid Rain permit issued under the State Acid Rain program or portion of the program until, and except to the extent that, the permit is replaced by a permit issued under this section. After the later of the date for publication of a notice in the **Federal Register** that the State operating permit program is currently approved by the Administrator or that the State Acid Rain program or portion of the program is currently accepted by the Administrator, the Administrator will suspend federal administration of Acid Rain permits effective in Phase II for sources and units to the extent that they

are subject to the State Acid Rain program or portion of the program, except as provided in paragraph (b)(4) of this section.

(4) After the State permitting authority becomes responsible for administering and enforcing Acid Rain permits effective in Phase II under § 72.73(a), the Administrator will continue to administer and enforce each Acid Rain permit issued under paragraph (a)(1), (b)(1), or (b)(2) of this section until, and except to the extent that, the permit is replaced by a permit issued under the State Acid Rain program. The State permitting authority may replace an Acid Rain permit issued under paragraph (a)(1), (b)(1), or (b)(2) of this section by issuing a permit under the State Acid Rain program by the expiration of the permit under paragraph (a)(1), (b)(1), or (b)(2) of this section. The Administrator may retain jurisdiction over the Acid Rain permits issued under paragraph (a)(1), (b)(1), or (b)(2) of this section for which the administrative or judicial review process is not complete and will address such retention of jurisdiction in a notice in the **Federal Register**.

(c) **Permit Issuance Deadline.** (1)(i) On or before January 1, 1998, the Administrator will issue an Acid Rain permit for Phase II setting forth the Acid Rain Program sulfur dioxide requirements for each affected unit (other than opt-in sources) at a source not under the jurisdiction of a State permitting authority that is responsible, as of January 1, 1997 (or such later date as the Administrator may establish), under § 72.73(a) of this section for administering and enforcing Acid Rain permits with such requirements; *provided* that the designated representative for the source submitted a timely and complete Acid Rain permit application in accordance with § 72.21. The failure by the Administrator to issue a permit in accordance with this paragraph shall be grounds for the filing of an appeal under part 78 of this chapter.

(ii) Each Acid Rain permit issued in accordance with this section shall have a term of 5 years commencing on its effective date. Each Acid Rain permit issued in accordance with paragraph (c)(1)(i) of this section shall take effect by the later of January 1, 2000 or, where a permit governs a unit under § 72.6(a)(3), the deadline for monitor certification under part 75 of this chapter.

(2) **Nitrogen Oxides.** Not later than 6 months following submission by the designated representative of an Acid Rain permit application for nitrogen oxides, the Administrator will amend

under § 72.83 the Acid Rain permit and add any NO_x early election plan that was approved under § 76.8 of this chapter and has not been terminated and reopen the Acid Rain permit for Phase II and add any other Acid Rain Program nitrogen oxides requirements for each affected source not under the jurisdiction of a State permitting authority that is responsible, as of January 1, 1997 (or such later date as the Administrator may establish), under § 72.73(a) for issuing Acid Rain permits with such requirements; *provided* that the designated representative for the source submitted a timely and complete Acid Rain permit application for nitrogen oxides in accordance with § 72.21.

(d) **Permit Issuance.** (1) The Administrator may utilize any or all of the provisions of subparts E and F of this part to administer Acid Rain permits as authorized under this section or may adopt by rulemaking portions of a State Acid Rain program in substitution of or in addition to provisions of subparts E and F of this part to administer such permits. The provisions of Acid Rain permits for Phase I or Phase II issued by the Administrator shall not be applicable requirements under part 70 of this chapter.

(2) The Administrator may delegate all or part of his or her responsibility, under this section, for administering and enforcing Phase II Acid Rain permits or opt-in permits to a State. Such delegation will be made consistent with the requirements of this part and the provisions governing delegation of a part 71 program under part 71 of this chapter.

33. Section 72.80 is amended by revising paragraphs (a), (b), (d), (e), (f), and (g) to read as follows:

§ 72.80 General.

(a) This subpart shall govern revisions to any Acid Rain permit issued by the Administrator and to the Acid Rain portion of any operating permit issued by a State permitting authority.

(b) Notwithstanding the operating permit revision procedures specified in parts 70 and 71 of this chapter, the provisions of this subpart shall govern revision of any Acid Rain Program permit provision.

* * * * *

(d) The terms of the Acid Rain permit shall apply while the permit revision is pending, except as provided in § 72.83 for administrative permit amendments.

(e) The standard requirements of § 72.9 shall not be modified or voided by a permit revision.

(f) Any permit revision involving incorporation of a compliance option that was not submitted for approval and comment during the permit issuance process or involving a change in a compliance option that was previously submitted, shall meet the requirements for applying for such compliance option under subpart D of this part and parts 74 and 76 of this chapter.

(g) Any designated representative who fails to submit any relevant information or who has submitted incorrect information in a permit revision shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or corrected information to the permitting authority.

* * * * *

34. Section 72.81 is amended by: removing from paragraph (c)(1)(ii) the words "and § 70.7(e)(4)(ii) of this chapter"; and revising paragraph (c)(2) to read as follows:

§ 72.81 Permit modifications.

* * * * *

(c) * * *

(2) For purposes of applying paragraph (c)(1) of this section, a requested permit modification shall be treated as a permit application, to the extent consistent with § 72.80(c) and (d).

35. Section 72.82 is amended by revising paragraphs (a) and (d) to read as follows:

§ 72.82 Fast-track modifications.

* * * * *

(a) If the Administrator is the permitting authority, the designated representative shall serve a copy of the fast-track modification on the Administrator and any person entitled to a written notice under § 72.65(b)(1)(ii) and (iii). If a State is the permitting authority, the designated representative shall serve such a copy on the Administrator, the permitting authority, and any person entitled to receive a written notice of a draft permit under the approved State operating permit program. Within 5 business days of serving such copies, the designated representative shall also give public notice by publication in a newspaper of general circulation in the area where the sources are located or in a State publication designed to give general public notice.

* * * * *

(d) Within 30 days of the close of the public comment period if the Administrator is the permitting authority or within 90 days of the close of the public comment period if a State is the permitting authority, the permitting authority shall consider the

fast-track modification and the comments received and approve, in whole or in part or with changes or conditions as appropriate, or disapprove the modification. A fast-track modification shall be subject to the same provisions for review by the Administrator and affected States as are applicable to a permit modification under § 72.81.

36. Section 72.83 is amended by: removing from paragraph (a)(10) the words "regulations implementing section 407 of the Act" and adding, in their place, the words "part 76 of this chapter"; and revising paragraphs (a)(12) and (b) and adding paragraphs (a)(13), (a)(14), (c), and (d) to read as follows:

§ 72.83 Administrative permit amendment.

(a) * * *

(12) The addition of a NO_x early election plan that was approved by the Administrator under § 76.8 of this chapter;

(13) The addition of an exemption for which the requirements have been met under § 72.7 or § 72.8 or which was approved by the permitting authority under § 72.14; and

(14) Incorporation of changes that the Administrator has determined to be similar to those in paragraphs (a)(1) through (13) of this section.

(b)(1) The permitting authority will take final action on an administrative permit amendment within 60 days, or, for the addition of an alternative emissions limitation demonstration period, within 90 days, of receipt of the requested amendment and may take such action without providing prior public notice. The source may implement any changes in the administrative permit amendment immediately upon submission of the requested amendment, *provided* that the requirements of paragraph (a) of this section are met.

(2) The permitting authority may, on its own motion, make an administrative permit amendment under paragraph (a)(3), (a)(4), (a)(12), or (a)(13) of this section at least 30 days after providing notice to the designated representative of the amendment and without providing any other prior public notice.

(c) The permitting authority will designate the permit revision under paragraph (b) of this section as having been made as an administrative permit amendment. Where a State is the permitting authority, the permitting authority shall submit the revised portion of the permit to the Administrator.

(d) An administrative amendment shall not be subject to the provisions for

review by the Administrator and affected States applicable to a permit modification under § 72.81.

37. Section 72.85 is amended by revising paragraphs (a) and (c) to read as follows:

§ 72.85 Permit reopenings.

(a) The permitting authority shall reopen an Acid Rain permit for cause whenever:

(1) Any additional requirement under the Acid Rain Program becomes applicable to any affected unit governed by the permit;

(2) The permitting authority determines that the permit contains a material mistake or that an inaccurate statement was made in establishing the emissions standards or other terms or conditions of the permit, unless the mistake or statement is corrected in accordance with § 72.83; or

(3) The permitting authority determines that the permit must be revised or revoked to assure compliance with Acid Rain Program requirements.

* * * * *

(c) As provided in §§ 72.73(b)(1) and 72.74(c)(2), the permitting authority shall reopen an Acid Rain permit to incorporate nitrogen oxides requirements, consistent with part 76 of this chapter.

* * * * *

38. Section 72.91 is amended by:

a. Removing from paragraph (b)(1)(i) the words "improved unit measures" and adding, in their place, the words "improved unit efficiency measures";

b. Removing from paragraph (b)(1)(iii) introductory text, the words "all figures" and adding, in their place, the words "each figure";

c. Removing from paragraph (b)(1)(iii)(B) the words "measures, and" and adding, in their place, the words "measures, or";

d. Removing from paragraph (b)(1)(iii)(C) the words "measures." and adding, in their place, the words "measures, except measures relating to generation efficiency.";

e. Removing from paragraph (b)(3) the words "unit efficiency measures" and adding, in their place, the words "improved unit efficiency measures";

f. Removing from paragraph (b)(4) introductory text, the word "units's" and adding, in its place, the word "unit's";

g. Removing from the formula in paragraph (b)(4) introductory text, the word "heat" and adding, in its place, the word "heat";

h. Removing from paragraph (b)(4)(i) the word "units'" and adding, in its place, the word "unit's"; revising paragraphs (b)(5), (b)(6), and (b)(7); and

i. Adding paragraphs (b)(1)(iv) and (b)(4)(iv) to read as follows:

§ 72.91 Phase I unit adjusted utilization.

* * * * *

(b) * * *

(1) * * *

(iv) The sum of the verified reductions in a unit's heat input from all measures implemented at the unit to reduce the unit's heat rate (whether the measures are treated as supply-side measures or improved unit efficiency measures) shall not exceed the generation (in kwh) attributed to the unit for the calendar year times the difference between the unit's heat rate for 1987 and the unit's heat rate for the calendar year.

* * * * *

(4) * * *

(iv) The allowances credited shall not exceed the total number of allowances deducted from the unit's compliance subaccount for the calendar year in accordance with §§ 72.92(a) and (c) and 73.35(b) of this chapter.

(5) If the total, included in the confirmation report, of the amount of verified reduction in the unit's heat input for energy conservation and improved unit efficiency measures is less than the total estimated in the unit's annual compliance certification report for such measures for the calendar year, then the designated representative shall include in the confirmation report the number of allowances to be deducted from the unit's compliance subaccount calculated in accordance with this paragraph (b)(5).

(i) If any allowances were deducted from the unit's compliance subaccount for the calendar year in accordance with §§ 72.92(a) and (c) and 73.35(b) of this chapter, then the number of allowances to be deducted under paragraph (b)(5) of this section equals the absolute value of the result of the formula for allowances credited under paragraph (b)(4) of this section (excluding paragraph (b)(4)(iv) of this section).

(ii) If no allowances were deducted from the unit's compliance subaccount for the calendar year in accordance with §§ 72.92(a) and (c) and 73.35(b) of this chapter:

(A) The designated representative shall recalculate the unit's adjusted utilization in accordance with paragraph (a) of this section, replacing the amounts for reduction from energy conservation and reduction from improved unit efficiency by the amount for verified heat input reduction. "Verified heat input reduction" is the total of the amounts of verified reduction in the unit's heat input (in mmBtu) from energy conservation and

improved unit efficiency measures included in the confirmation report.

(B) After recalculating the adjusted utilization under paragraph (b)(5)(ii)(A) of this section for all Phase I units that are in the unit's dispatch system and to which paragraph (b)(5) of this section is applicable, the designated representative shall calculate the number of allowances to be surrendered in accordance with § 72.92(c)(2) using the recalculated adjusted utilizations of such Phase I units.

(C) The allowances to be deducted under paragraph (b)(5) of this section shall equal the amount under paragraph (b)(5)(ii)(B) of this section, *provided* that if the amount calculated under this paragraph (b)(5)(ii)(C) is equal to or less than zero, then the amount of allowances to be deducted is zero.

(6) The Administrator will determine the amount of allowances that would have been included in the unit's compliance subaccount and the amount of excess emissions of sulfur dioxide that would have resulted if the deductions made under § 73.35(b) of this chapter had been based on the verified, rather than the estimated, reduction in the unit's heat input from energy conservation and improved unit efficiency measures.

(7) The Administrator will determine whether the amount of excess emissions of sulfur dioxide under paragraph (b)(6) of this section differs from the amount of excess emissions determined under § 73.35(b) of this chapter based on the annual compliance certification report. If the amounts differ, the Administrator will determine: The number of allowances that should be deducted to offset any increase in excess emissions or returned to account for any decrease in excess emissions; and the amount of excess emissions penalty (excluding interest) that should be paid or returned to account for the change in excess emissions. The Administrator will deduct immediately from the unit's compliance subaccount the amount of allowances that he or she determines is necessary to offset any increase in excess emissions or will return immediately to the unit's compliance subaccount the amount of allowances that he or she determines is necessary to account for any decrease in excess emissions. The designated representative may identify the serial numbers of the allowances to be deducted or returned. In the absence of such identification, the deduction will be on a first-in, first-out basis under § 73.35(b)(2) of this chapter and the

return will be at the Administrator's discretion.

* * * * *

39. Section 72.95 is amended by revising the formula in the introductory text and adding paragraph (d) to read as follows:

§ 72.95 Allowance deduction formula.

* * * * *

Total allowances deducted = Tons emitted + Allowances surrendered for underutilization + Allowances deducted for Phase I extensions + Allowances deducted for substitution or compensating units

Where:

* * * * *

(d) "Allowances deducted for substitution or compensating units" is the total number of allowances calculated in accordance with the surrender requirements specified under § 72.41(d)(3) or (e)(1)(iii)(B) or § 72.43(d)(2).

Part 73—[AMENDED]

40. The authority citation for part 73 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651 *et seq.*

41. Section 73.10 is amended by revising the section heading and adding paragraph (b)(3) to read as follows:

§ 73.10 Initial allocations for phase I and phase II.

* * * * *

(b) * * *

(3) Notwithstanding the amounts in Table 2 of this section, the unadjusted basic allowances for years 2000–2009 and for years 2010 and thereafter for Louisiana, Rodemacher 2 are 20,774.

* * * * *

42. Section 73.90 is amended by: removing from the formula in paragraph (c)(3) the words "Total Allowances Requested" and adding, in their place, the words "35,000"; removing from the formula in paragraph (c)(3) the words "35,000" and adding, in their place, the words "Total Allowances Requested"; and revising paragraphs (a)(1), (a)(2), and (a)(3) to read as follows:

§ 73.90 Allowance allocations for small diesel refineries.

(a) * * *

(1) Photocopies of Form EIA–810 for each month of calendar years 1988 through 1990 for the refinery;

(2) Photocopies of Form EIA–810 for each month of calendar years 1988 through 1990 for each refinery owned or controlled by the refiner that owns or controls the refinery seeking certification; and

(3) A letter certified by the certifying official that the submitted photocopies are exact duplicates of those forms filed

with the Department of Energy for 1988 through 1990.

BILLING CODE 6560-50-P

$$\text{Refinery Allowances} = \text{the lesser of} \left[\begin{array}{l} \text{Allowances Requested} \times \frac{35,000}{\text{Total Allowances Requested}} \\ \text{or} \\ 1,500 \end{array} \right]$$

BILLING CODE 6560-50-C

* * * * *

PART 74—[AMENDED]

43. The authority citation for part 74 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

§ 74.2 [Amended]

44. Section 74.2 is amended by removing the words “a written exemption under § 72.7 or § 72.8 of this chapter” and adding, in their place, the words “an exemption under § 72.7, § 72.8 or § 72.14 of this chapter”.

PART 75—[AMENDED]

45. The authority citation for part 75 is revised to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

§ 75.67 [Amended]

46. Section 75.67 is amended by removing and reserving paragraph (a).

PART 77—[AMENDED]

47. The authority citation continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

48. Section 77.3 is amended by revising paragraphs (d)(3), (5), and (6) to read as follows:

§ 77.3 Offset plans for excess emissions of sulfur dioxide.

* * * * *

(d) * * *

(3) At the designated representative's option, the number of allowances to be deducted from the unit's Allowance Tracking System account to offset the excess emissions for the year for which the plan is submitted.

* * * * *

(5) A statement either that allowances to offset the excess emissions are to be deducted immediately from the unit's compliance subaccount or that they are to be deducted on a specified date in a subsequent year.

(6) If the proposed offset plan does not propose an immediate deduction of

allowances under paragraph (d)(5) of this section, a demonstration that such a deduction will interfere with electric reliability.

49. Section 77.4 is amended by revising paragraphs (b)(1), (c)(2)(i), (f)(2)(i), (g)(2)(i)(B), (g)(2)(i)(C), the last two sentences of (k)(1), and (k)(2) to read as follows:

§ 77.4 Administrator's action on proposed offset plans.

* * * * *

(b) *Review of proposed offset plans.*
(1) If the designated representative submits a complete proposed offset plan for immediate deduction, from the unit's compliance subaccount, of allowances required to offset excess emissions of sulfur dioxide, the Administrator will approve the proposed offset plan without further review and will serve written notice of any approval on the designated representative. The Administrator will also give notice of any approval in the **Federal Register**. The plans will be incorporated in the unit's Acid Rain permit in accordance with § 72.84 of this chapter (automatic permit amendment) and will not be subject to the requirements of paragraphs (d) through (k) of this section.

* * * * *

(c) * * *

(2)(i) The designated representative shall submit the information required under paragraph (c)(1) of this section within a reasonable period determined by the Administrator.

* * * * *

(f) * * *

(2) * * *

(i) The reasons, and supporting authority, for approval or disapproval of any proposed offset plan that does not require immediate deduction of allowances, including references to applicable statutory or regulatory provisions and to the administrative record; and

* * * * *

(g) * * *

(2) * * *

(i) * * *

(B) The air pollution control agencies of affected States; and

(C) Any interested person.

* * * * *

(k) * * *

(1) * * * The Administrator will serve a copy of any approved offset plan and the response to comments on the designated representative for the affected unit involved and serve written notice of the approval or disapproval of the offset plan on any persons who are entitled to written notice under paragraphs (g)(2)(i) (B) and (C) of this section or who submitted written or oral comments on the approval or disapproval of the draft offset plan. The Administrator will also give notice in the **Federal Register**.

(2) The Administrator will approve an offset plan requiring immediate deduction from the unit's compliance subaccount of all allowances necessary to offset the excess emissions except to the extent the designated representative of the unit demonstrates that such a deduction will interfere with electric reliability.

* * * * *

50. Section 77.6 is amended by revising paragraph (a) to read as follows:

§ 77.6 Penalties for excess emissions of sulfur dioxide and nitrogen oxides.

(a)(1) If excess emissions of sulfur dioxide or nitrogen oxide occur at an affected unit during any year, the owners and operators of the affected unit shall pay, without demand, an excess emissions penalty, as calculated under paragraph (b) of this section.
(2) If one or more affected units governed by an approved NO_x averaging plan under § 76.11 of this chapter fail (after applying § 76.11(d)(1)(ii)(C) of this chapter) to meet their respective alternative contemporaneous emission limitations or annual heat input limits, then excess emissions of nitrogen oxides occur during the year at each such unit. The sum of the excess emissions of nitrogen oxides of such units shall equal the amount determined under § 76.13(b)

of this chapter. The owners and operators of such units shall pay an excess emissions penalty, as calculated under paragraph (b) of this section using the sum of the excess emissions of nitrogen oxides of such units.

(3) Except as otherwise provided in this paragraph (a)(3), payment under paragraphs (a) (1) or (2) of this section shall be submitted to the Administrator by 30 days after the date on which the Administrator serves the designated representative a notice that the process of recordation set forth in § 73.34(a) of this chapter is completed or by July 1 of the year after the year in which the excess emissions occurred, whichever date is earlier. Payment under paragraph (a)(1) of this section for any increase in excess emissions of sulfur dioxide determined after adjustments made under § 72.91(b) of this chapter shall be submitted to the Administrator by 30 days after the date on which the Administrator serves the designated representative a notice that process set forth in § 72.91(b) of this chapter is completed.

* * * * *

PART 78—[AMENDED]

51. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

52. Section 78.1 is amended by revising paragraphs (a) and (b)(1)(v) to read as follows:

§ 78.1 Purpose and scope.

(a)(1) This part shall govern appeals of any final decision of the Administrator under parts 72, 73, 74, 75, 76, and 77 of this chapter; *provided* that matters listed § 78.3(d) and preliminary, procedural, or intermediate decisions, such as draft Acid Rain permits, may not be appealed.

(2) Filing an appeal, and exhausting administrative remedies, under this part shall be a prerequisite to seeking judicial review. For purposes of judicial review, final agency action occurs only when a decision appealable under this part is issued and the procedures under this part for appealing the decision are exhausted.

(b) * * *

(1) * * *

(v) The issuance or denial of an exemption under § 72.14 of this chapter;

* * * * *

§ 78.3 [Amended]

53. Section 78.3 is amended by:

a. Removing from paragraph (b)(1) the words “60 days” and adding, in their place, the words “30 days”;

b. Removing from paragraph (b)(1) the words “action.” and adding, in their place, the words “action and shall not meet the prerequisite for judicial review under § 78.1(a)(2).”;

c. Removing from paragraph (b)(3)(ii) the words “the persons entitled to written notice under § 72.65(b)(1) (ii), (iii), and (iv) of this chapter.” and adding, in their place, the words “the air pollution control agencies of affected States and any interested person.”;

d. Adding at the end of paragraph (c)(6) the word “and”; removing from paragraph (c)(7) the words “; and” and adding, in their place, the word “.”;

e. Removing paragraph (c)(8);

f. Removing paragraph (d)(1); and

g. Redesignating paragraphs (d)(2), (d)(3), and (d)(4) as paragraphs (d)(1), (d)(2), and (d)(3) respectively.

§ 78.4 [Amended]

54. Section 78.4 is amended by: removing from paragraph (c)(1) the words “7 days” and adding, in its place, the words “7 days (or other reasonable period established by the Environmental Appeals Board or Presiding Officer).”; and removing from paragraph (c)(1) the words “it, unless the Environmental Appeals Board or Presiding Officer authorizes a longer time based on good cause.” and adding, in their place, the words “it.”.

55. Section 78.5 is amended by removing from paragraph (a) the words “to submit a claim of error notification” and adding, in their place, the words “a claim of error notification was submitted”.

§ 78.5 [Amended]

§ 78.7 [Removed and reserved]

8056. Section 78.7 is removed and reserved.

§ 78.11 [Amended]

57. Section 78.11 is amended by: removing from paragraph (a) the words “30 days” and adding, in their place, the words “30 days (or other shorter, reasonable period established by the Administrator when giving notice)”.

§ 78.12 [Amended]

58. Section 78.12 is amended by: removing from paragraph (a)(2) the

words “a written exemption under §§ 72.7 or 72.8” and adding, in their place, the words “an exemption under § 72.14”.

§ 78.14 [Amended]

59. Section 78.14 is amended by: removing from paragraph (a), introductory text, the word “theses” and adding, in its place, the word “these”; removing from paragraph (a)(10) the words “15 days” and adding, in their place, the words “15 days (or other shorter, reasonable period established by the Presiding Officer)”;

and removing from paragraph (c)(1) the words “Rule 408 of”.

§ 78.15 [Amended]

60. Section 78.15 is amended by: removing from paragraph (c) the words “10 days” and adding, in their place, the words “10 days (or other shorter, reasonable period established by the Presiding Officer)”;

and removing the last sentence from paragraph (c).

§ 78.16 [Amended]

61. Section 78.16 is amended by: removing from paragraphs (d)(1) and (d)(2) the words “7 days” and adding, in their place, the words “7 days (or other shorter, reasonable period established by the Presiding Officer)”.

§ 78.17 [Amended]

62. Section 78.17 is amended by: removing the words “45 days” and adding, in their place, the words “45 days (or other shorter, reasonable period established by the Presiding Officer)”;

and removing the words “, for good cause shown, may shorten or extend the time for filing and”.

§ 78.18 [Amended]

63. Section 78.18 is amended by: removing from paragraph (b), introductory text, the words “30 days after service unless within that time:” and adding, in their place, the words “unless:”.

§ 78.20 [Amended]

64. Section 78.20 is amended by: removing from paragraph (b) the words “30 days” and adding, in their place, the words “45 days (or other shorter, reasonable period established by the Environmental Appeals Board)”.

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